PB-226 547

PROGRAM FOR REDUCTION OF NOx FROM TANGENTIAL COAL-FIRED BOILERS. PHASE I

COMBUSTION ENGINEERING, INCORPORATED

PREPARED FOR

ENVIRONMENTAL PROTECTION AGENCY

AUGUST 1973

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NTIS
National Technical Information Service
U. S. DEPARTMENT OF COMMERCE

BIBLIOGRAPHIC DATA SHEET

1. Report No. EPA-650/2-73-005

2.

PB 226 547

4. Title and Subtitle

Program for Reduction of NOx from Tangential Coal-Fired Boilers--Phase I

5. Report Date August 1973

6.

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8. Performing Organization Rept. No.

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10. Project/Task/Work Unit No.

11. Contract/Grant No. 68-02-0264

12. Sponsoring Organization Name and Address

EPA, Office of Research and Development
NERC-RTP, Control Systems Laboratory
Research Triangle Park, North Carolina 27711

13. Type of Report & Period Covered Phase I

14.

15. Supplementary Notes

16. Abstracts

The report gives results of Phase I of a study to develop a pilot field-test program to evaluate combustion modification techniques to reduce NOx emissions from tangentially coal-fired steam-generating units. Alabama Power Co. (Barry Station, unit I) is to be the test unit. The report includes details of the preliminary test program, including analytical measurement and sampling techniques, engineering drawings, cost estimates, and schedules. Phase II will require 24 months. Overfire air is the least expensive technique for controlling NOx, incurring no loss in unit efficiency or increased operating expenses. Flue gas recirculation is significantly more costly, requires additional fan power, and (in existing units) could result in a 10-20% decrease in load capability due to increased gas flow weights. Water injection into the fuel-firing zone has the lowest initial equipment cost; however, losses in unit efficiency (resulting in increased fuel costs and significant water consumption) make it the most expensive system to operate. The cost of applying controls to existing units generally is twice that of new units.

17. Key Words and Document Analysis. 17a. Descriptors

Air Pollution
Nitrogen Oxides
Abatement
Combustion Control
Flue Gases
Circulation
Water Injection
Combustion Chambers
Economic Analysis
Coal

17b. Identifiers/Open-Ended Terms

NOx Reduction
Tangential Firing
Combustion Modifications
Overfire Air
Flue Gas Recirculation
Air Pollution Control
Stationary Sources

17c. COSATI Field/Group 13B, 14A, 21B

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NATIONAL TECHNICAL
INFORMATION SERVICE
U S Department of Commerce
Springfield VA 22151

18. Availability Statement Unlimited

19. Security Class (This Report) UNCLASSIFIED

20. Security Class (This Page UNCLASSIFIED

21. No. of Pages 195 183

22. Price $5.25

FORM NTIS-35 (REV. 3-72)

USCOMM-DC 14952-P72

1a

EPA-650/2-73-005

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PHASE I

by

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Program Element No. 1A2014

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OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D. C. 20460

August 1973

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This report has been reviewed by the Environmental Protection Agency and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

FOREWORD

This report presents the findings of Phase I of a "Pilot Field Test Program to Study Methods for Reduction of NO_x Formation in Tangentially Coal Fired Steam Generating Units" performed under the sponsorship of the Office of Air Programs of the Environmental Protection Agency (Contract No. 62-02-0264). Phase I of the program consisted of selecting a suitable utility field steam generator to be modified for experimental studies to evaluate NO_x emissions control. This effort included the preparation of engineering drawings, a detailed preliminary test program, a cost estimate and detailed time schedule of the following program phases and a preliminary application economic study indicating the cost range of each combustion technique as applied to existing and new steam generators.

Mr. C. E. Blakeslee was the contractor's program coordinator, Mr. A. P. Selker the contractor's principal investigator and Mr. David G. Lachapelle the EPA Project Officer during this program phase.

We wish to acknowledge the cooperation of the Alabama Power Company and in particular the assistance of the personnel of the Barry Station in conducting the unit operating survey.

Finally we wish to express our appreciation to all Combustion Engineering, Inc. personnel who participated in this program and in particular for the technical contributions made by Messrs. W. A. Stevens, R. F. Swope, W. H. Clayton, M. J. Hargrove, R. W. Robinson, R. W. Borio and P. R. Purrington of Combustion Engineering, Inc.

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I. INTRODUCTION

A. Purpose of Program

The purpose of this program was to investigate various means for NO_x emission control as applied to coal fired utility steam generators. While current coal firing combustion and control technology had minimized smoke, CO, hydrocarbon and solid combustible emissions, proven techniques for the control of NO_x had not been fully developed and evaluated. Review of combustion process modifications which had been found effective in reducing NO_x emissions from oil and gas fired steam generators and recent staged combustion simulations with coal firing indicated that gas recirculation to the firing zone and/or staged combustion should be evaluated as commercially feasible methods of NO_x reduction. For these reasons a program was developed to evaluate the feasibility of these as well as other methods of NO_x control on a commercially sized pilot plant unit. This unit would be modified to incorporate the systems to be studied for evaluation of potential operating and control problems and the establishment of optimum methods for both transient and long term operation. This report presents the results of program Phase I during which a suitable unit was selected, engineering drawings and cost of modifications prepared, a preliminary test program written, and NO_x control system costs for new and existing units developed.

B. Scope of Program

Program Phase I was conducted as part of a projected five phase program to identify, develop and recommend the most promising combustion modification techniques for control of NO_x, without objectionable increases in related pollutants, from tangentially coal fired utility steam generators. Phase I was accomplished in accordance with the following task identification.

Task I - Selection of a suitable tangentially coal fired unit for emission control modification and testing.

Task II - Preparation of a detailed preliminary test program.

Task III - Preparation of engineering drawings, modification costs and time schedule.

Task IV - Estimate modification cost ranges for each combustion modification technique as applied to existing and new boilers.

II. PROGRAM OBJECTIVES

The objective of Phase I was to select a tangentially coal fired steam generator suitable for modification and performance of a test program to be conducted in Phase IV and prepare all specified drawings, cost estimates and schedules.

Specifically, this objective is defined by the following Phase I tasks.

Task I - Selection of a Suitable Tangentially Coal Fired Steam Generator

The following criteria were considered in selection of the test unit.

a. The unit is representative of current tangential coal firing designs.

b. The size of the unit selected will be large enough to minimize data extrapolation to larger current designs while remaining small enough to minimize modification costs and permit flexibility in conducting the experimental program.

c. The unit location, transportation facilities and coal handling and storage facilities shall permit testing of various coals.

d. The utility involved will cooperate and participate in making the unit available for modification and testing.

Task II - Preparation of the Detailed Test Program

The test program will be designed to investigate the effects of the combustion process variables and modifications on NO_x, SO_x, carbon loss in the fly ash, CO and HC emission levels.

The following variables were to be considered:

a. Process Variables

Excess Air

Unit Loading

Biased Firing

Coal Type

b. Combustion System Modifications

Flue Gas Recirculation to:

- Secondary Air Ducts
- Coal Pulverizers
- Combination of Above

Overfire Air

Air Preheat Temperature

Water Injection to the Fuel Firing Zone

The test program will provide for evaluation of modified operation with respect to unit transient and long term operation.

Task III - Development of Engineering Drawings and Costs

The following drawings and documentation were to be developed:

a. All engineering drawings except detailed drawings required for modification, fabrication and installation.

b. Estimated purchased equipment, material, erection and test costs to conduct the program.

c. Detailed time schedule for conducting the program.

Task IV - Combustion Technique Application Costs to New and Existing Steam Generators

Based on the results of the Phase I evaluation and current contractors knowledge, a cost range would be developed for applying the NO_x control techniques evaluated in this study to new and existing steam generators.

III. RESULTS AND CONCLUSIONS

Task I

Alabama Power Company, Barry Station, Unit I was selected as a suitable test unit for this program. The unit meets the requirements as defined by Task I objectives and Alabama Power Company has expressed a willingness to cooperate in this program.

Task II

Two preliminary test programs were developed utilizing statistical test design methods where possible. This principle enabled the programs to be designed for maximum information output for each test. The first test program was designed to evaluate all combustion modifications listed under Task II. The second test program was designed to evaluate specific process variables with the major emphasis on evaluating and optimizing biased and overfire air firing. All necessary analytical measurements and sampling techniques required to evaluate the effect of combustion modifications on unit performance and emissions were identified and methods of measurement developed.

Task III

Engineering drawings and cost estimates for the proposed unit modifications were completed. Cost estimates were developed for combined as well as individual overfire air and gas recirculation systems. The results of the task indicate that the required systems can be designed and installed as proposed or as individual systems with allowances for future additions.

Task IV

The combustion application technique study indicated that overfire air is the least expensive system for controlling NO_X emissions on new and existing units with gas recirculation and water injection being more expensive. In general, the cost of applying control techniques to existing units is twice that of new units.

IV. RECOMMENDATIONS

1. The modification and test phases of the program should be undertaken essentially as proposed. As a minimum, the program should evaluate and optimize biased and overfire air firing.
2. The test program should be limited to the long term evaluation of one instead of two additional coal types. This decision would be made pending the results of the base coal and first additional coal test results.
3. A baseline test program should be considered to establish unit operation and emission levels prior to modification.
4. Should the individual installation of any given portion of the proposed control systems be considered such as overfire air, provisions should be made in the system design for installation of the remaining systems at a future date.
5. It is essential to the successful completion of this program that the utility company involvement initiated during Phase I be continued and expanded in the follow-on program phases to include review and approval of design modifications and test programs. Program scheduling and installation of control systems must be coordinated with planned unit outages.

V. DISCUSSION

Task I - UNIT SELECTION

To select a test unit meeting the criteria specified under Task I, Combustion Engineering conducted a survey of utility companies using tangentially coal fired steam generators to determine their interest in participating in the NO_X control program. As a result of this survey, seven (7) utility companies expressed a desire to cooperate with CE in the program. These companies were subsequently reviewed to determine if they had within their generating systems units meeting the remaining criteria specified for the test unit.

Of several units found to be generally acceptable for the test program, Alabama Power Co., Barry Station Unit No. 1 was finally selected.

This unit is a natural circulation, balanced draft, steam generator, firing coal through four elevations of tilting tangential fuel nozzles. The superheat steam capacity at maximum continuous rating is 900,000 LBS/HR main steam flow with a superheat outlet temperature and pressure of 1000 F and 1875 PSIG. Superheat and reheat temperatures are controlled by fuel nozzle tilt and spray desuperheating. A side elevation of this unit is shown in Figure 1.

The criteria upon which the selection was based are as follows.

1. The unit is representative of the tangentially coal fired steam generators currently designed by CE which facilitates the transfer of technology to existing and new boiler designs.

2. The unit, while representative of current utility boiler design, is small enough (125 MW) to minimize modification costs and permit a versatile experimental program. The control system installation can be coordinated with a planned outage for installation of a hot electrostatic precipitator. This precipitator would eliminate the need for additional dust removal equipment to protect the gas recirculation system fan.

3. The unit location permits testing of various coals without incurring additional coal transportation costs. Coals currently being burned at the station include both local Alabama and Illinois varieties. The station has existing facilities for receiving and handling of both rail and barge coal deliveries.

4. Alabama Power Company had expressed their willingness to cooperate and participate in this program by making the unit available for the required modifications and tests.

5. The results of a unit operating survey indicated that Barry 1 is acceptable for the planned experimental NO_X control study modifications. A detailed report of this study is included in Section VI. Briefly, unit operating flexibility, ash handling systems, fan capacities and normal operation NO_X levels were found to be acceptable for the purposes of this program. A plot of NO_X values versus excess air at various unit loadings is shown in Figure 2.

Task II - DETAILED TEST PROGRAMS

The detailed test programs were developed using a statistical program design approach. In this manner maximum program efficiency can be attained by obtaining the maximum informational output from each test.

Using this approach the individual variables considered for evaluation were first identified and then the minimum number of variable combinations which must be tested to properly evaluate each variable was established.

The individual variables identified for evaluation in one case were as follows:

ALABAMA POWER COMPANY
BARRY No. 1

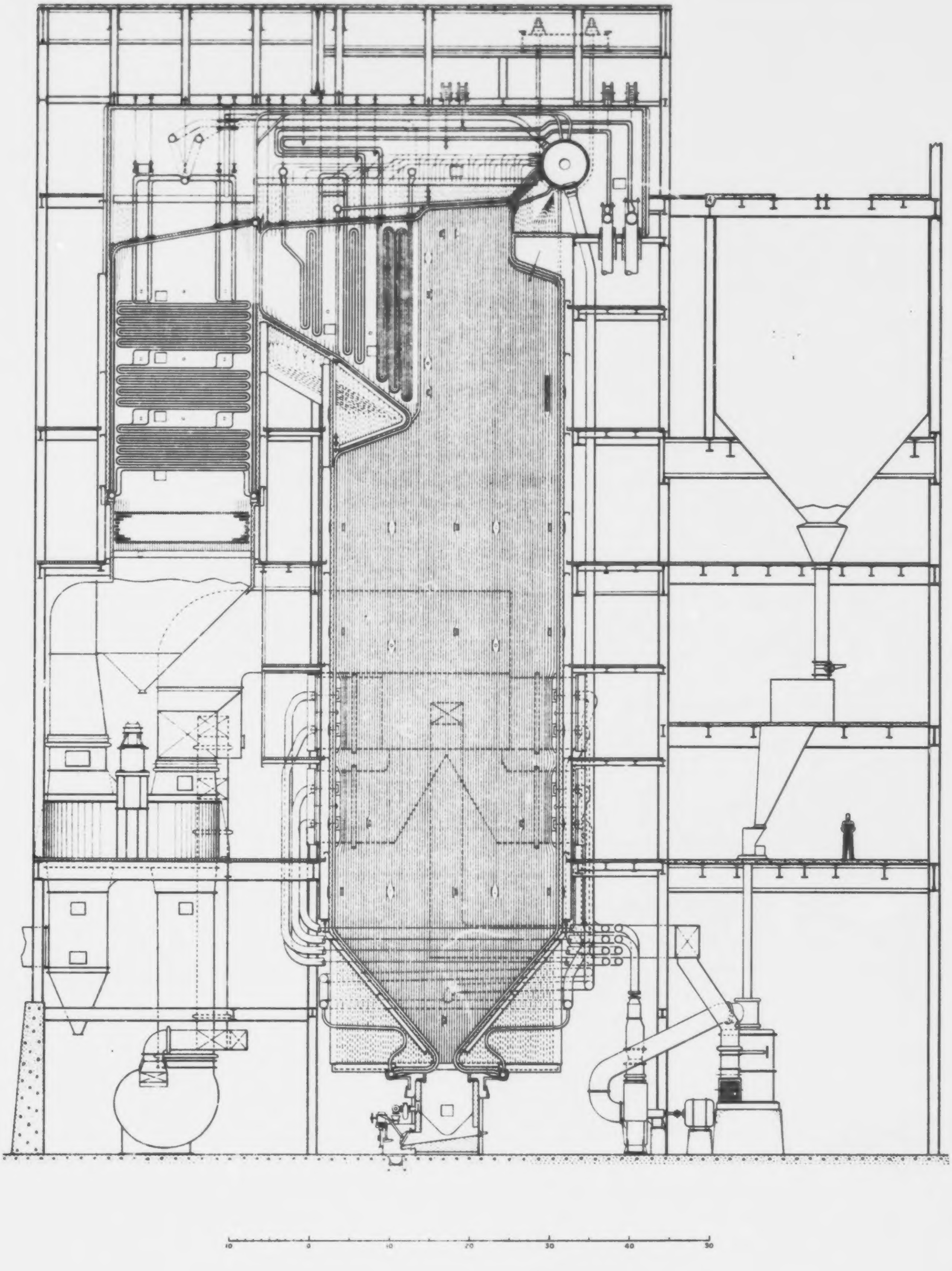

10
0
10
20
30
40
50

FIGURE 1

ALABAMA POWER COMPANY - BARRY NO. 1

NO_X VS. PERCENT EXCESS AIR

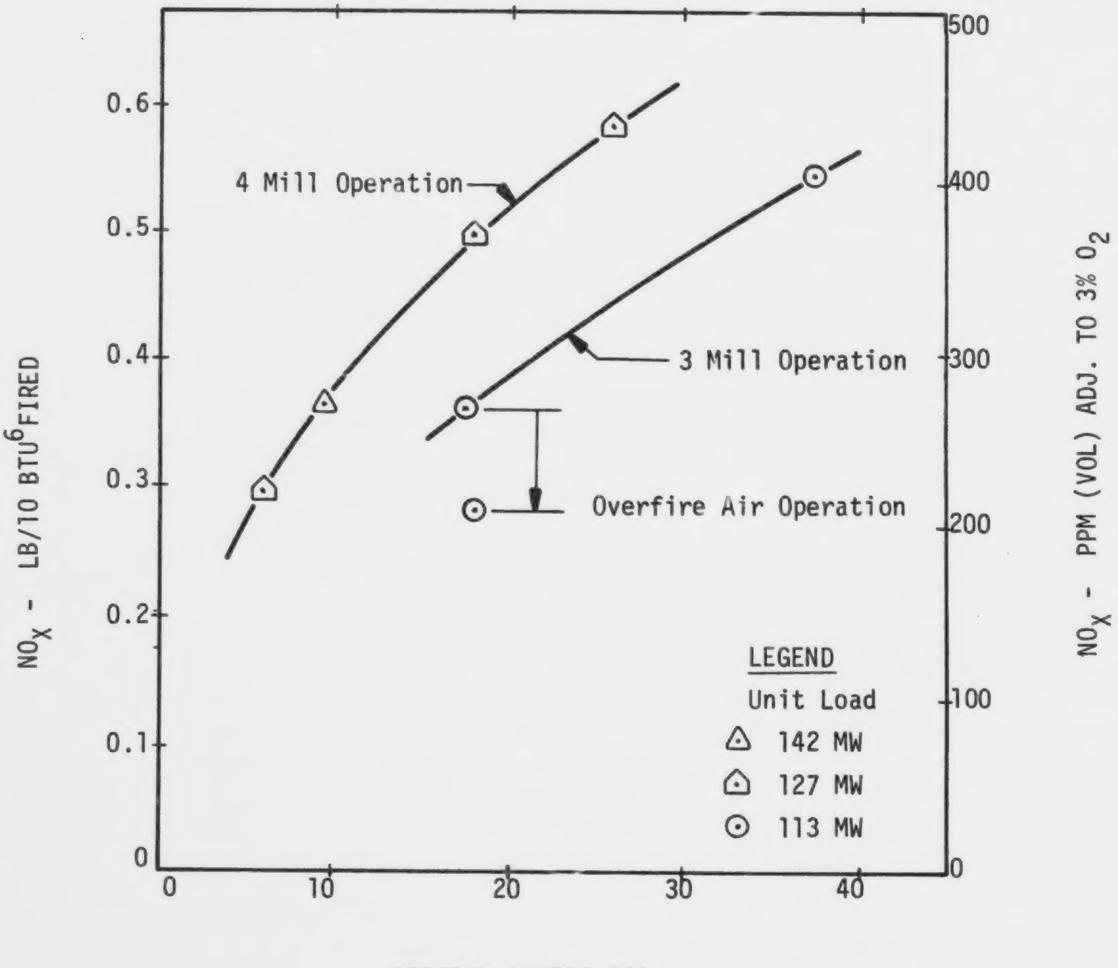


FIGURE 2

Excess Air

Unit Loading

Air Preheat Temperature

Biased Firing

Gas Recirculation to:

  a. Secondary Air Ducts

  b. Coal Pulverizers

  c. Combination of the above

Overfire Air

Water Injection to the Firing Zone

For the second case, the variables to be evaluated were:

Excess Air

Unit Loading

Biased Firing

Overfire Air

Based on these variables the detailed test programs were developed and are presented in Section VI.

The degree to which each process variable or modification would be applied and the process measurements necessary to evaluate unit performance follow.

Process Modifications

A. Overfire Air System

The overfire air system was designed to introduce a maximum of 20 percent of full load combustion air above the fuel admission nozzles through two additional compartments in each furnace corner located approximately eight feet above the fuel admission zone.

Overfire air can also be supplied to the furnace through the top two compartments of the existing windbox when the upper elevation of fuel nozzles is not in use. The overfire air nozzles will tilt ±30° in the vertical plane independently of the main fuel and air nozzles. Independent dampers for each overfire air compartment will be provided as a means to study the influence of location and velocity of overfire air introduction.

B. Gas Recirculation System

The gas recirculation system was designed to recirculate flue gas to the secondary air duct and coal pulverizers either separately or in combination. The system would provide for a maximum of 40 percent recirculation at 80 percent unit loading and permit substituting gas recirculation for hot air to the coal pulverizers while introducing tempering air in the conventional manner. A gas recirculation temperature range of 300 to 650F would be possible by varying the weight ratio of flue gas taken from the air preheater gas inlet and outlet.

C. Air Preheat System

The preheated air temperature entering the secondary air duct can be varied by bypassing the air and/or gas side of the air preheaters to provide the maximum system flexibility.

D. Water Injection System

Water injection can be admitted into the furnace through two elevations of atomizing spray nozzles located between the top two and bottom two fuel nozzle elevations. A maximum injection rate of 50 pounds per million BTU fired can be used.

Process Variables

Excess air, unit load, and fuel and air distribution will be varied within the current limitations of the existing equipment. These limits were evaluated in the unit operating survey conducted in Task I and are presented in Section VI.

Process Measurements

Operation of the unit as proposed in the experimental study will produce variations in unit operation and thermal performance. The following process measurements are required to properly assess the impact of these changes on new unit design and the retrofitting of existing units.

A. Furnace Absorption

Recirculating gases to the secondary air compartments and staging of combustion air will effect changes in both peak and average furnace waterwall temperatures and absorption rates. The waterwall crown temperatures and absorption rates must therefore be determined to evaluate the impact of variations in average and peak rates and absorption profiles on unit design.

B. Furnace Corrosion Probes

Unit operation with staged combustion air may result in local reducing atmospheres within the furnace envelope, resulting in accelerated waterwall corrosion rates. To assess the impact of this type of operation on waterwall wastage, furnace corrosion probes will be utilized.

C. Sensible Heat Leaving the Furnace

Variations in furnace heat absorption rates due to modifying the combustion process will result in increasing or decreasing the sensible heat leaving the furnace envelope and entering the superheat and reheat sections of the unit. To determine the sensible heat leaving the furnace, the exit gas temperature will be measured at the vertical furnace outlet plane using water cooled probes with radiation shielded thermocouples.

D. Superheat, Reheat and Economizer Section Absorptions

Variations in the gas temperature and gas flow leaving the furnace envelope and entering the convective sections of the unit will affect the total heat pickup of each section. To assess the impact of modified operation on superheat, reheat and economizer performance, the absorption rates for each section will be determined.

Variation in absorption rates may require resurfacing when retrofitting existing units for modified operation.

E. Air Heater Performance

Air and gas temperatures and gas side oxygen concentrations entering and leaving the air heater are required to calculate air heater performance, unit efficiency, heat losses and air and gas flow rates.

F. Fuel and Ash Analysis

During each test, a representative fuel sample must be obtained for later analysis. The fuel analyses are required to perform combustion calculations necessary to determine excess air levels and unit gas and air flow rates. Pulverized coal fineness samples will be obtained to determine the effect, if any, on furnace wall deposit characteristics, solid combustibles losses, NO_x levels and related emissions.

In addition, coal ash analyses are required to determine ash properties such as base/acid ratios and ash deformation, softening and fluid temperatures necessary for evaluating the furnace wall deposit characteristics of coal fuels. Furnace bottom ash, fly ash and coal pulverizer rejects analyses are also required to determine heat losses and material balances. Specific instrumentation and methods to be used in measuring these process variables and the flue gas emission constituents are defined in the detailed test plan.

Task III - ENGINEERING DRAWINGS, COST ESTIMATES AND DETAILED TIME SCHEDULES

Engineering Drawings

Arrangement drawings were completed showing necessary duct arrangements for the overfire air and gas recirculation systems, the overfire air register arrangements and control system interfaces with the existing unit. The general arrangement drawings for the ductwork indicate that the proposed control systems can be physically installed within the existing station without serious structural interferences.

The modification ductwork final locations were determined by an extensive design review and engineering field check of actual existing equipment configurations and locations.

Cost Estimates

The cost of fabricating, installing and testing the overfire air and gas recirculation systems were estimated both as a complete system and as individually installed systems. These estimates do not include additional fuel costs incurred during the test program as Alabama Power Company has agreed to assume these costs.

Detailed Time Schedules

Due to difficulties encountered in establishing when authorization to proceed with follow-on program phases would be received, it was not possible to finalize a detailed time schedule for installation of the control systems. Schedules based on elapsed time from start of contract were prepared and are shown in Figures 3 and 4. These schedules must be coordinated with a unit outage occurring in the tenth to twelfth program month. Such an outage is currently available in the spring of 1974.

The drawings and cost estimates prepared under Task III are presented in Section VI.

Task IV - COMBUSTION TECHNIQUE APPLICATION COSTS

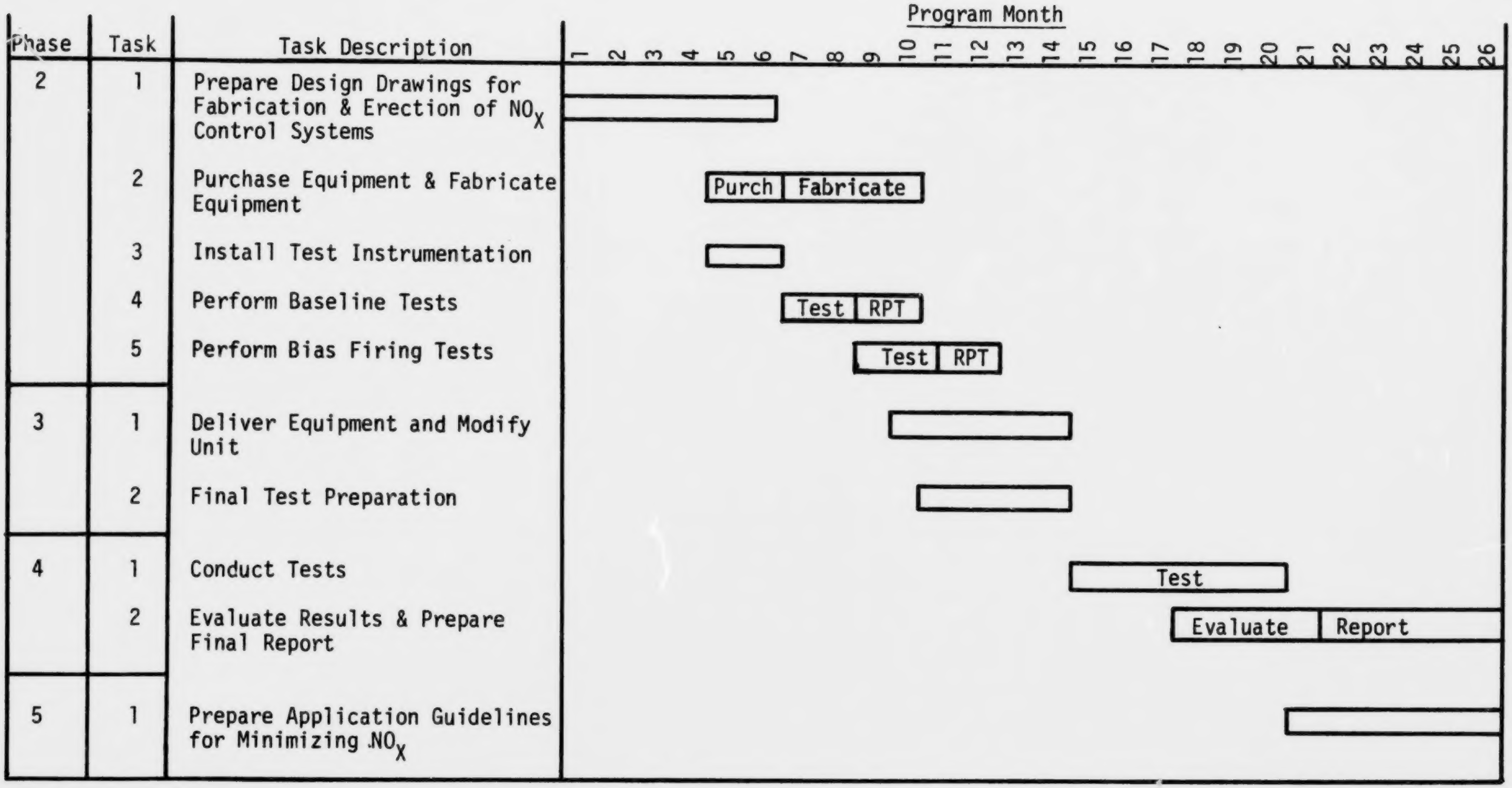
Application Study Results

Based on the cost estimates developed under Task III and Combustion Engineering, Inc.'s current knowledge, cost ranges were developed for applying the NO_X control techniques proposed in this program to new and existing unit designs. These cost ranges are illustrated in Figures 5 and 6.

Specifically, four possible methods of reducing NO_X emission levels from tangentially coal fired steam generators were evaluated and the cost trends for each method estimated for both new and existing units. The reduction methods considered included overfire air, gas recirculation to the secondary air ducts, gas recirculation to the coal pulverizer/primary air system and furnace water injection. The cost trends for these methods were projected over a unit size range of 125 to 750 MW.

PROGRAM SCHEDULE

FOR EVALUATION OF OVERFIRE AIR, GAS RECIRCULATION, AIR
PREHEAT AND WATER INJECTION SYSTEMS AND EXISTING PROCESS VARIABLES



Phase	Task	Task Description
2	1	Prepare Design Drawings for Fabrication & Erection of NO_X Control Systems
	2	Purchase Equipment & Fabricate Equipment
	3	Install Test Instrumentation
	4	Perform Baseline Tests
	5	Perform Bias Firing Tests
3	1	Deliver Equipment and Modify Unit
	2	Final Test Preparation
4	1	Conduct Tests
	2	Evaluate Results & Prepare Final Report
5	1	Prepare Application Guidelines for Minimizing NO_X

FIGURE 3

PROGRAM SCHEDULE

FOR EVALUATION OF BIASED AND OVERFIRE AIR FIRING AND EXISTING PROCESS VARIABLES

Phase	Task	Task Description
2	1	Prepare Design Drawings for Fabrication & Erection of NO_x Control Systems
	2	Purchase Equipment & Fabricate Equipment
	3	Install Test Instrumentation
	4	Perform Baseline Tests
	5	Perform Bias Firing Tests
3	1	Deliver Equipment and Modify Unit
	2	Final Test Preparation
4	1	Conduct Tests
	2	Evaluate Results & Prepare Final Report
5	1	Prepare Application Guidelines for Minimizing NO_x

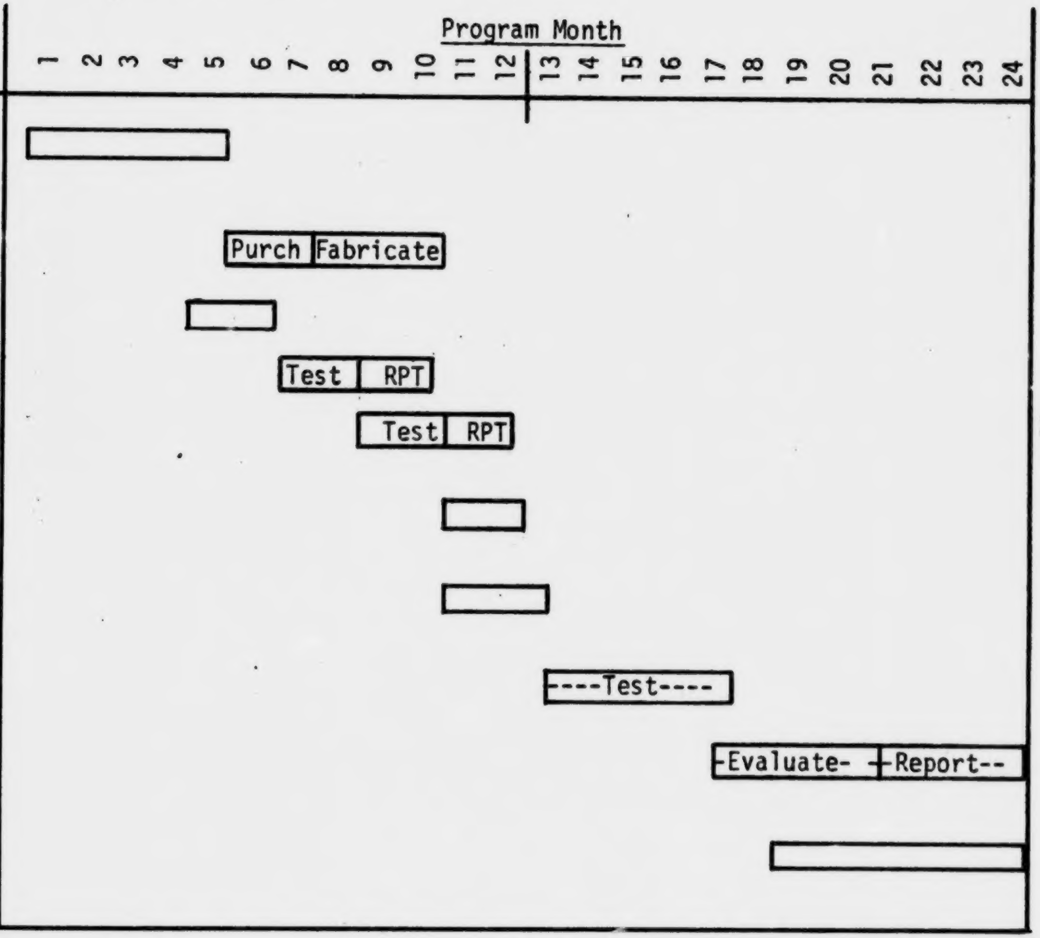


FIGURE 4

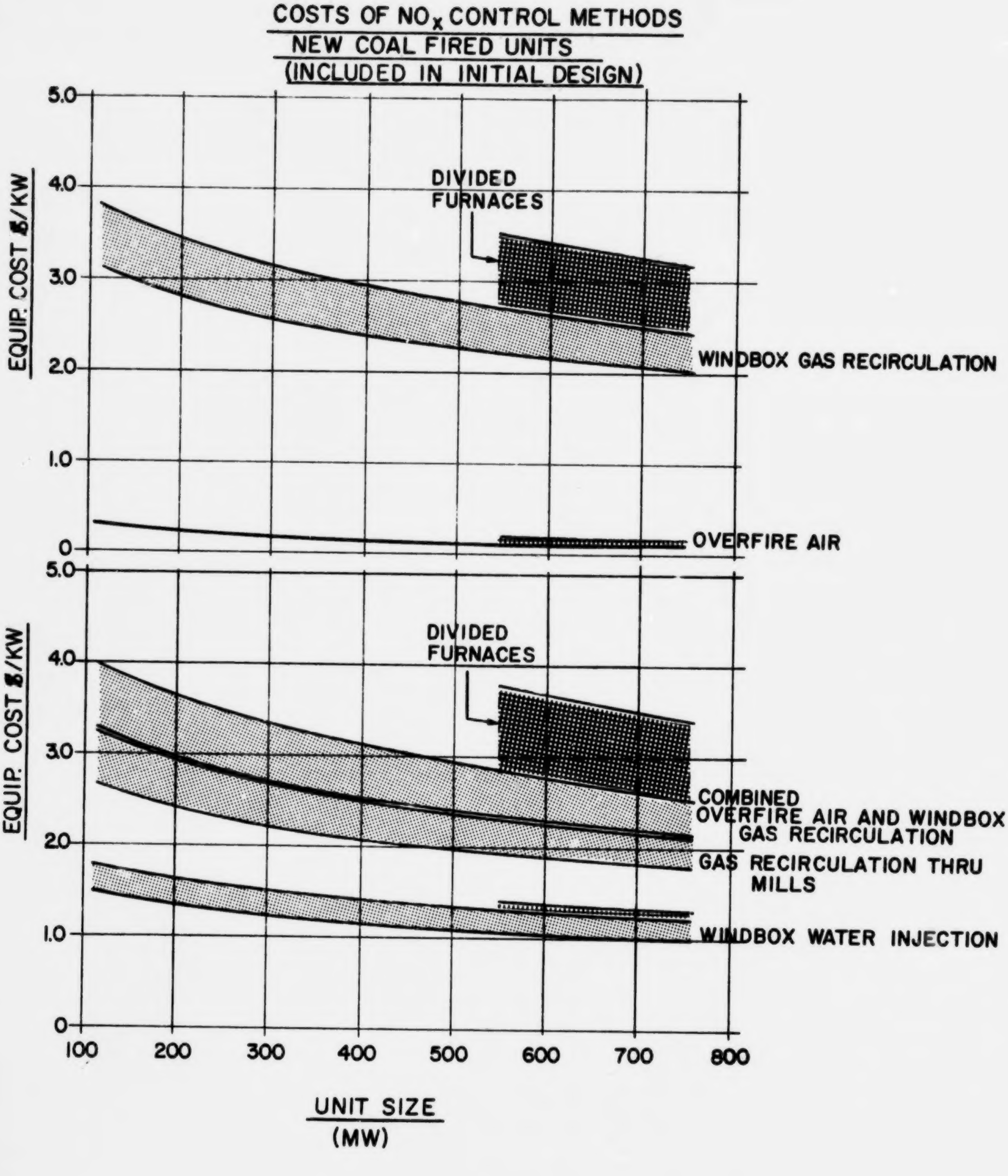

COSTS OF NO$_x$ CONTROL METHODS
NEW COAL FIRED UNITS
(INCLUDED IN INITIAL DESIGN)
EQUIP. COST $/KW
5.0
4.0
3.0
2.0
1.0
0
DIVIDED FURNACES
WINDBOX GAS RECIRCULATION
OVERFIRE AIR
EQUIP. COST $/KW
5.0
4.0
3.0
2.0
1.0
0
DIVIDED FURNACES
COMBINED OVERFIRE AIR AND WINDBOX GAS RECIRCULATION
GAS RECIRCULATION THRU MILLS
WINDBOX WATER INJECTION
100
200
300
400
500
600
700
800
UNIT SIZE
(MW)

FIGURE 5

COSTS OF NO_x CONTROL METHODS
EXISTING COAL FIRED UNITS
(HEATING SURFACE CHANGES NOT INCLUDED)

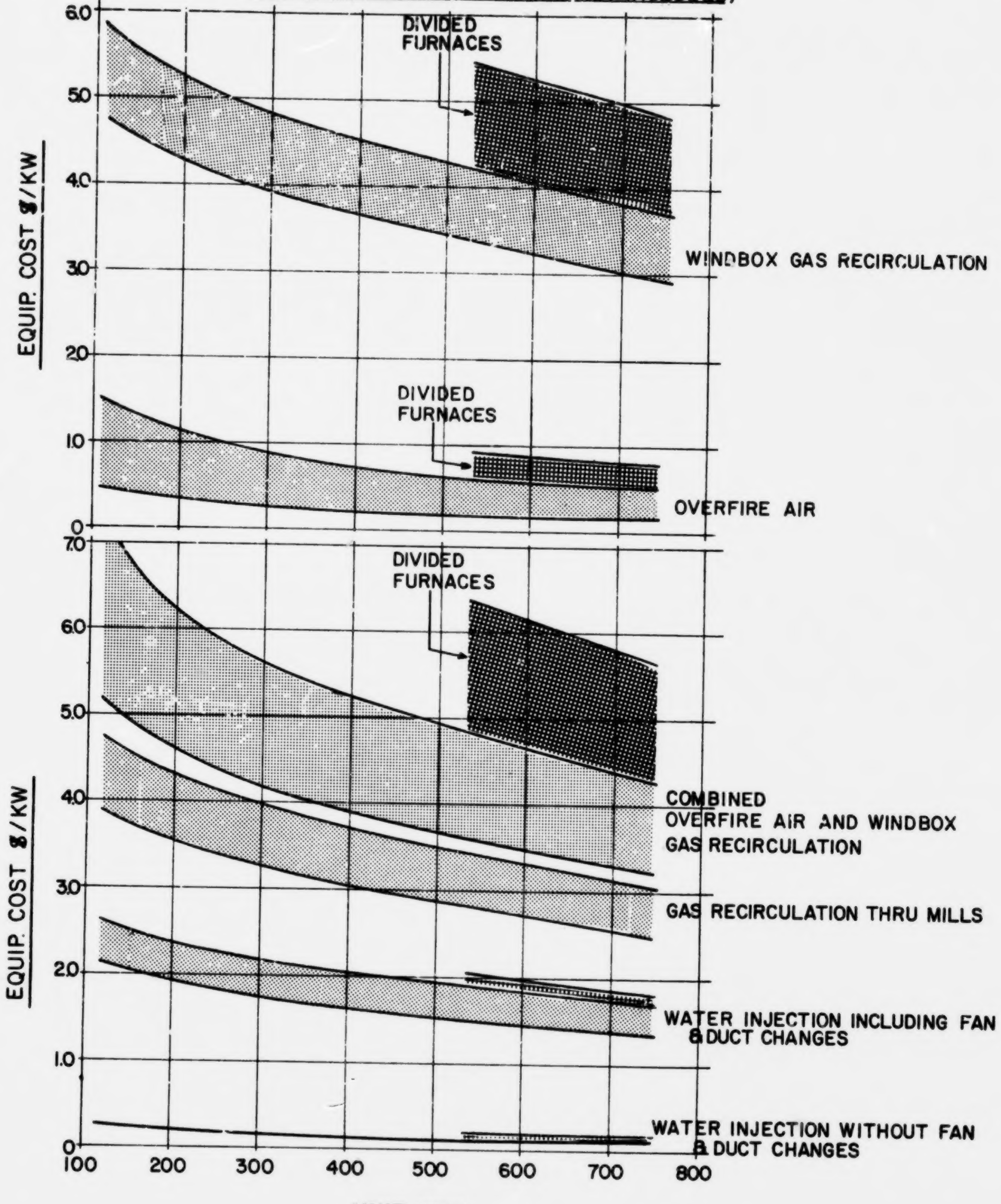


FIGURE 6

The results of the study indicate that for any given unit size (450 MW chosen for an example comparison) the lowest cost method is found to be overfire air which results in a .14 to .50 $/KW additional unit cost for a new or existing unit respectively.

This method incurs no loss in unit efficiency or increased operating expenses.

Gas recirculation introduced either through the secondary air ducts or the coal pulverizers and primary transport air system results in higher equipment costs than overfire air and requires additional power for fan operation.

Water injection introduced into the fuel firing zone of the unit is attractive from the standpoint of low initial equipment costs, however, losses in unit efficiency resulting in increased fuel costs and significant water consumption make it the most expensive system to operate.

The use of either gas recirculation or water injection in existing units could result in a 10 to 20 percent decrease in load capability due to increased gas flow weights.

The following conclusions were drawn from this study.

1. The lowest cost method for reducing NO_x emission levels on new and existing units is the incorporation of an overfire air system. No additional operating costs are involved.
2. Gas recirculation either to the windbox or coal pulverizers is a promising control system but is significantly more costly than overfire air and requires additional fan power. In existing units, the necessity to reduce unit capacity to maintain acceptable gas velocities imposes an additional penalty.
3. Gas recirculation to the coal pulverizers would cost approximately 15 percent less than windbox gas recirculation, however, this method may require increased excess air to maintain adequate combustion.
4. Water injection has initially low equipment costs, but due to high operating costs resulting from losses in unit efficiency, is the least desirable of the systems evaluated. This system may also require reduced unit capacity.
5. In general, the cost of applying any of the control methods studied to an existing unit is approximately twice that of a new unit design.

Application Study Design

For the purpose of this study the following five modes of unit operation were chosen as potentially effective means for the reduction of NO_x emissions.

The quantities of overfire air, gas recirculation and water injection selected for the economic evaluation, while reasonable, do not necessarily represent commercially feasible operation or control methods which would be recommended by Combustion Engineering, Inc.

1. Introducing 20 percent of the total combustion air over the fuel firing zone as overfire air.
2. Introducing 30 percent flue gas recirculation through the secondary air ducts and windbox compartments.
3. Combining the 20 percent overfire air and 30 percent flue gas recirculation of 1 and 2.
4. Introducing 17 percent flue gas recirculation through the transport air/coal pulverizer system.
5. Introducing water injection into the fuel firing zone at a rate of 5 percent of total evaporation.

The economic comparisons of the five NO_x emission control methods were based on 1973 delivered and erected costs for the steam generators and associated equipment.

The cost estimates presented for the revision of existing units were based on studies performed on units within the 125 to 750 MW size range including those costs generated under Phase I, Task 3, for the Barry No. 1 unit. The cost estimates presented for incorporating control methods in new unit designs were based on Combustion Engineering experience and current practice for overfire air and gas recirculation systems.

As can be seen from Figures 5 and 6 the cost ranges for existing units vary more widely than new units. This is due mainly to variations in unit design and construction which either hinder or aid the installation of a given control system. For example, an overfire air system may be designed as a windbox extension unless existing structural requirements and obstructions necessitate installation of a more costly system including extensive ductwork and individual air injection ports. The same condition exists for water injection systems when the need to maintain unit capacity dictates changes in unit ducting. Except where noted, all system costs are estimated on a ±10 percent basis. The cost range of the combined overfire air and windbox gas recirculation system was arrived at as the sum of the cost ranges of the individual systems. The cost ranges presented for existing units do not include any changes to heating surface as these changes must be calculated on an individual unit basis. Due to variations in existing designs, heating surfaces may increase, decrease or remain unchanged for a given control method.

At approximately 600 MW, single cell fired furnaces reach a practical size limit and divided furnace designs are employed. Since a divided tangentially fired furnace has double the firing corners of a single cell furnace, the costs of windboxes and ducts increase significantly as shown on Figures 5 and 6. As shown, the costs of overfire air, windbox gas recirculation and windbox water injection increase from 30 to 50 percent.

In addition to the increased capital costs resulting from including an NO_X control system in a unit design, the increased unit operating costs must be considered. The increased annual operating costs were determined for a 100, 450 and 750 MW unit of new design and are shown in Table 1. The equipment costs shown are determined from Figure 5. Using the 450 MW unit as an example at a rate of .14 \$/KW results in an increase in unit capital cost of \$63,000. The additional annual fixed charges, fuel and fan power costs for each of the five NO_X control methods studied and the criteria on which these costs are based are also listed in Table 1.

Again using the 450 MW unit as an example the study indicates that water injection is the most expensive system to operate at .332 mills/KWHR due primarily to increased fuel costs resulting from losses in unit efficiency. The least expensive control system to operate was overfire air at .004 mills/KWHR with gas recirculation either alone or in combination with overfire air ranging from .108 to .121 mills/KWHR.

To put these operating costs in perspective, they can be compared to "average" generating costs presented in Table 1 for various sizes of unmodified units.

Operating costs were developed only for a new unit design as it is possible to assume that design parameters would remain unchanged from a unit designed without NO_X controls. However for existing units, gas and air flow rate changes, increased draft losses and changes in unit load capabilities would vary to such a degree that each unit would have to be treated individually regardless of rating and costs would vary to such a degree that they would not be useful to a general study.

VI. ATTACHMENTS

This section includes all material referenced in the preceding sections of this report.

ATTACHMENT	
I	Unit Operating Survey
II	Detailed Test Programs
III	Engineering Drawings
IV	Cost Estimates for Conducting Pilot Field Test Programs
V	Combustion Technique Application Study

TABLE I

1973 OPERATING COSTS OF NO_x CONTROL METHODS FOR NEW COAL FIRED UNITS

SINGLE FURNACE

Control Method		Overfire Air (20%)			Windbox Flue Gas Recirc. (30%)			Combination of 1 and 2			Coal Mill Flue Gas Recirc. (17%)			Water Injection		
MW Rating		100	450	750	100	450	750	100	450	750	100	450	750	100	450	750
Equipment Costs	10^3\$	31	63	90	350	1185	1650	375	1248	1800	300	1015	1425	160	560	825
Annual Fixed Charge	10^3\$	5	10	14	56	190	264	60	200	288	48	162	228	26	90	132
Additional Annual Fuel Cost	10^3\$	---	---	---	---	---	---	---	---	---	---	---	---	147	660	1099
Additional Annual Fan Power Cost	10^3\$	---	---	---	21	95	158	21	95	158	22	100	166	13	58	97
Total Annual Cost	10^3\$	5	10	14	77	285	422	81	295	446	70	262	394	186	808	1328
Operating Cost	MILLS/KWHR	0.009	0.004	0.003	0.143	0.117	0.104	0.150	0.121	0.110	0.130	0.108	0.097	0.344	0.332	0.327 (G)

Based on:
- A. Delivered and erected equipment costs (± 10% accuracy). Excluding contingency and interest during construction.
- B. 5400 HR/YR at rated MW and net plant heat rate of 9400 BTU/KWHR.
- C. 50¢/10^6BTU coal cost.
- D. \$250/HP fan power cost, or \$40/HP per year.
- E. Annual fixed charge rate of 16%.
- F. Operating costs are ± 10%.
- G. Does not include cost of water piping in plant or cost of makeup water.

Base unit operating costs* for coal fired power plants excluding SO_2 removal systems.

Unit Size	MW	100	450	750
Operating Cost	MILLS/KWHR	16.2	13.5	12.6

*Includes 1973 capital costs, labor, maintenance, fuel costs +20% contingency +17% interest during construction.

SECTION VI

ATTACHMENT I

UNIT OPERATING SURVEY

COMBUSTION ENGINEERING, INC.

FIELD TESTING AND
PERFORMANCE RESULTS

TEST REPORT 72-11

ENVIRONMENTAL PROTECTION AGENCY PILOT FIELD TEST PROGRAM TO STUDY METHODS FOR REDUCTIONS OF NO_X FORMATION IN TANGENTIALLY COAL FIRED STEAM GENERATING UNITS

PHASE I - TASK I

UNIT OPERATING SURVEY

ALABAMA POWER CO.
BARRY STATION, UNIT #1
CONTRACT 6472
PROJECT 900126

A. P. SELKER

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UNIT DESCRIPTION

Barry Station, Unit #1 is a natural circulation, balanced draft boiler firing coal through four elevations of tilting tangential fuel nozzles. The steam capacity at maximum continuous rating (MCR) is 900,000 LBS/HR main steam flow with a superheat outlet temperature and pressure of 1000 F and 1875 PSIG. Superheat and reheat temperatures are controlled by fuel nozzle tilt and spray desuperheating. A unit side elevation is shown on Figure 1.

TEST OBJECTIVES

The objectives of this test program were to:

1. Determine the acceptability of Barry #1 for modification to evaluate overfire air and windbox gas recirculation as NO_x controls for coal firing.
2. Obtain NO_x emission levels and all supporting data while varying the following operating conditions.
   - A. Percent Oxygen
   - B. Overfire air through the top elevation of auxiliary and fuel air compartments.
3. Obtain NO_x emission levels and all supporting data while operating at overfire air conditions for a twenty-four hour period.
4. Record operational difficulties and equipment limitations in obtaining and maintaining test conditions of Objectives 2 and 3.
5. Obtain draft loss data at all test conditions to assist in sizing of the gas recirculation fan and associated ductwork.

CONCLUSIONS

1. The test program was performed while firing Illinois coal. The results indicate that Barry #1 is acceptable for the planned experimental NO_x control study modifications as follows.
   - A. There were no unit operating difficulties encountered during the test program which would limit the proposed unit modification and experimental study.
   - B. The unit can be operated at peak load conditions for extended periods of time using normal ash removal procedures indicating the adequacy of present wall blowing, soot blowing and ash removal facilities.

C. Approximately 88 percent unit load can be carried with lower three mill operation permitting overfire air to be introduced through the top fuel and air compartments.

D. Operation with maximum excess air at the lower three mill, 88% MCR condition indicates that 40% gas recirculation may be introduced into the unit windbox at normal operating excess air without exceeding existing ID and FD fan capacities or superheat and reheat temperature limits. The amount of recirculation acceptable from a combustion standpoint will be established during the experimental test program.

E. Operation at 6 percent excess air is possible at 100 and 88 percent MCR without encountering unit slagging or flame instability indicating that low excess air operation may be studied. Normal plant operation at peak load conditions is 9.5 percent excess air.

2. NO_x levels obtained during this program are sufficiently representative of the levels obtained from current large furnace designs.

DISCUSSION

Test Data Acquisition

The flue gas samples for determination of the NO_x emission levels and percent oxygen were obtained at the economizer outlet duct. The flue gas samples were drawn from an 8 point grid and blended to obtain an accurate average oxygen and NO_x reading.

The NO_x levels were determined by the phenol-disulfonic acid procedure as specified in ASTM Procedure D-1608. All NO_x levels are reported in PPM/VOL on a dry basis adjusted to 3 percent oxygen and as LB $NO_2/10^6$BTU fired. A summary of the NO_x test data is tabulated on Sheet 1. Unit draft losses were determined using both station data and test manometers. Draft loss data is tabulated on Sheets 2 and 3 and the draft loss test points are shown on Figure 1. The fuel air compartment pressures versus compartment damper positions shown on Sheet 3 were obtained in support of analytical effort to calculate compartment flow rates based on damper positions. Station instrumentation was used to obtain unit operating data which is tabulated on Sheet 4.

Coal samples were obtained during each day of testing. The samples were obtained from each feeder and blended to form a composite sample. The analysis of these samples are shown on Sheet 5. A plot of the excess air versus the products of combustion, percent CO_2 and percent O_2 as calculated from the ultimate fuel analysis is shown on Figure 4.

Performance Calculations

Unit gas weights and efficiencies were calculated for each test condition using operating board data and are tabulated on test data Sheet 1. The unit efficiency was determined for each test by the heat balance losses method. Unit gas weight was determined by dividing the total unit absorption (BTU/HR) by the efficiency to obtain the unit heat input (BTU/HR) which was then multiplied by the wet products of combustion (LB/10^6BTU fired - determined from the fuel analysis - Figure 4) to obtain the pounds per hour of gas flow.

An evaluation of FD and ID fan capacity when recirculating flue gas to the furnace are detailed in a later section of this report.

Maximum Continuous Rating Evaluation

Tests 1, 2 and 3 were conducted at 100 percent maximum continuous rating (MCR: 127 MW) to determine unit draft losses over the maximum possible range of excess air and the NO_x emission levels at these excess airs. As shown on Figures 2 and 3 and the following table, the draft loss and NO_x level increased with increased excess air (gas weight).

TEST NO.	UNIT DRAFT LOSS-"WG FD FAN OUT-ID FAN IN	NO_x PPM (VOL)	EXCESS AIR PERCENT	GAS WT. 10^3LB/HR	MAIN STEAM FLOW 10^3LB/HR
1	23.8	433	26	1163.4	880
2	21.2	370	18	1112.2	900
3	13.5	220	6	978.3	900

The range of excess air obtainable was limited to a maximum of 26 percent by ID fan capacity and to a minimum of 6 percent by allowable superheat/reheat outlet steam temperature differential.

Peak Load Evaluation

Test 4 was conducted at peak load (112 percent MCR: 142 MW) to determine draft losses and NO_x emission levels at the maximum possible unit loading.

TEST NO.	UNIT DRAFT LOSS-"WG FD FAN OUT-ID FAN IN	NO_x PPM (VOL)	EXCESS AIR PERCENT	GAS WT. 10^3LB/HR	MAIN STEAM FLOW 10^3LB/HR
4	23.3	271	9.5	1106.8	975

The excess air was limited to 9.5 percent by ID fan capacity. The NO_x level of 271 PPM compares well with the levels obtained at 100 percent MCR operation as shown on Figure 3. Unit draft loss versus gas weight is shown on Figure 2. Unit operation was observed for eight of approximately twenty-four hours of continuous operation at peak load. No unit operating difficulties such as furnace slagging or ash removel problems were noted during this period. The 112 percent MCR loading is normally carried in day to day operation.

Lower Three Mill Operation

Tests 5, 6, 7 and 8 were conducted to determine the maximum unit loading obtainable with the lower three coal elevations in service, the range of excess air obtainable, unit draft loss and the effect of overfire air on NO_x emission levels at normal operating excess air. A twenty-four hour evaluation of overfire air operation was not possible due to unit load demand. The results of these tests are as follows:

TEST NO.	UNIT DRAFT LOSS-"WG FD FAN OUT-ID FAN IN	NO_X PPM (VOL)	EXCESS AIR PERCENT	GAS WT. 10^3LB/HR	MAIN STEAM FLOW 10^3LB/HR
5	24	405	37.5	1091.3	760
6	18.5	268	17.5	917.8	770
*7	17.4	209	18	930.3	765
8	15.55	---	6	812.5	765

*Overfire Air Operation

A maximum unit loading of approximately 88 percent MCR was obtainable with the lower three elevations of coal mills in operation.

The range of excess air at this loading was limited to a maximum of 37.5 percen by ID fan capacity and to a minimum of 6.0 percent by allowable superheat/reheat outlet steam temperature differential. At normal operating excess air (17.5 percent) opening the top elevation fuel and auxiliary dampers reduced the NO_X levels by 22 percent.

FD & ID Fan Capacity Evaluation

The calculated gas weights for Test 6 indicate that at 88% unit loading, 40 percent gas recirculation can be introduced through the windbox compartments without exceeding unit fan capacities. The gas weights used in this determination are as follows.

At normal operation with 17.5% excess air (Test 6) the following gas weights and draft losses were determined.

LOCATION	DRAFT LOSS-"WG	$\triangle$P "WG	GAS & AIR WEIGHTS X10^3LB/HR
Air from FD Fan Out. to Air Heater Air Out.	4.25	7.75	957.6*
Air from Air Heater Air Outlet to Lower Furnace	3.5		883.8
Gas from Lower Furnace to Air Heater Gas Inlet	3.45	10.75	917.8
Gas from Air Heater Gas Inlet to ID Fan Inlet	7.3		991.6*

*Air and gas weight assuming 8% air heater leakage. Air weight includes mill tempering air and does not include hot air recirculation.

Introducing 40% gas recirculation will increase the gas weight between the lower furnace and the air heater gas inlet to $1.4 \times 917.8 \times 10^3 = 1284.9 \times 10^3$ LB/HR.

The pressure drop in this section will therefore increase to:

$$\Delta P = 3.45 \left(\frac{1284.9}{917.8}\right)^2 = 6.76\text{"WG}$$

The air and gas weight between the air heater air outlet and the lower furnace will increase to 1250.9×10^3 LB/HR with a corresponding $\Delta P = 3.5 (1250.9/883.8)^2 = 6.86$"WG.

The unit gas weights and draft losses at 40% gas recirculation are therefore as follows.

LOCATION	DRAFT LOSS-"WG	ΔP "WG	GAS & AIR WEIGHTS X10^3LB/HR
Air from FD Fan Outlet to Air Heater Air Outlet	4.25	11.25	957.6
Air from Air Heater Air Outlet to Lower Furnace	7.00		1250.9
Gas from Lower Furnace to Air Heater Gas Inlet	6.76	14.06	1284.9
Gas from Air Heater Gas Inlet to ID Fan Inlet	7.3		991.6

The total pressure drop from the lower furnace to the ID fan inlet increases to 14.06 "WG which is within the ID fan capacity of 14.25 "WG established in Test 5. The pressure drop is 9.75 "WG from the FD fan outlet to the lower furnace at 73% FD fan loading. When extrapolated to 100% FD fan loading at 865 RPM the maximum allowable pressure drop increases to 11.9 "WG which is greater than the total calculated head of 11.25 "WG.

The superheat and reheat outlet temperatures at maximum excess air were 992 F and 927 F respectively without the use of desuperheat sprays and at a fuel nozzle tilt of -2 degrees.

A. P. Selker

A. P. Selker

APS:REB

DRAFT LOSS TEST POINT LOCATIONS

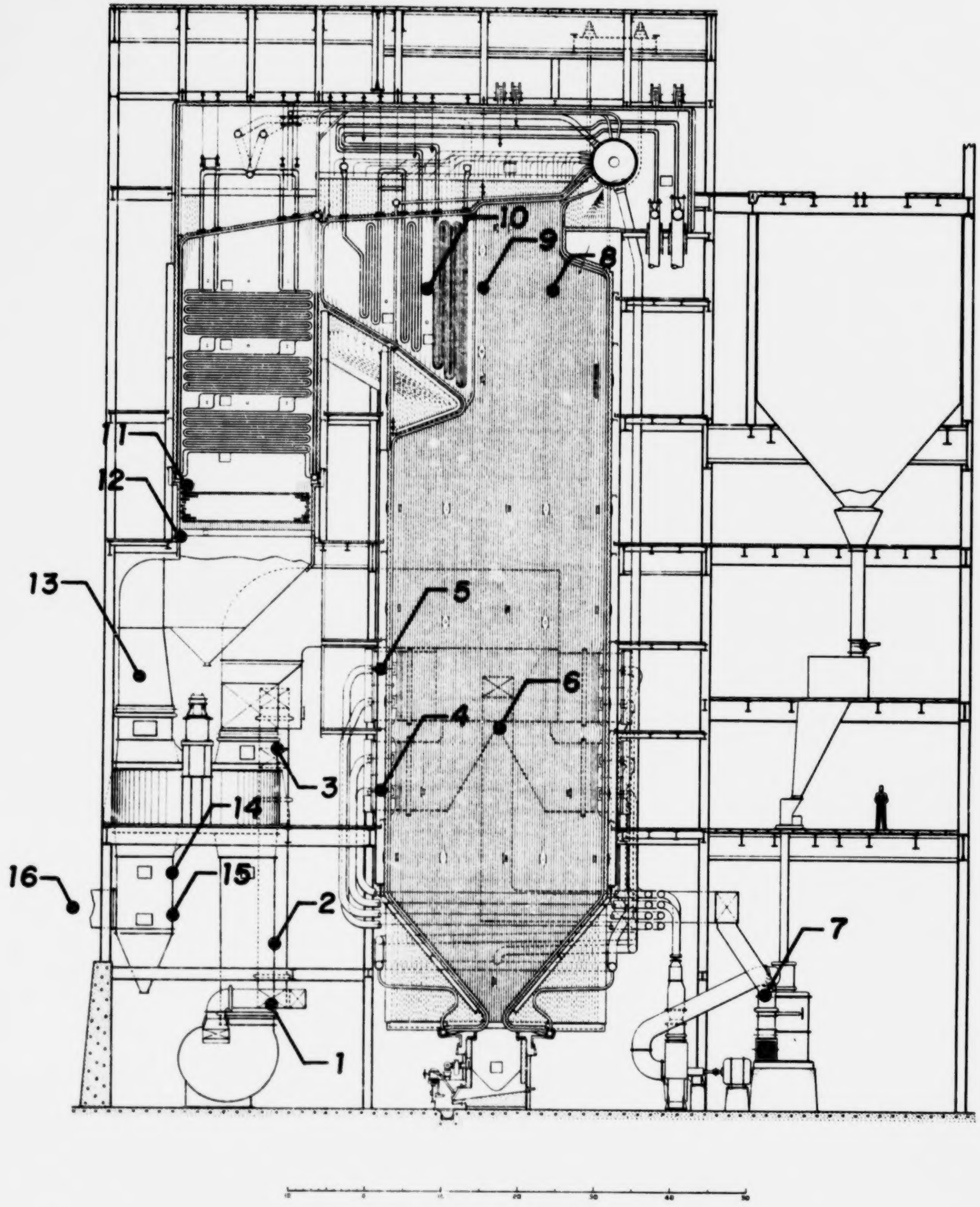

10
9
8
11
12
13
5
6
4
3
14
16
15
2
7
1
10
0
10
20
30
40
50

FIGURE 1

DRAFT LOSS VS. UNIT GAS WEIGHT

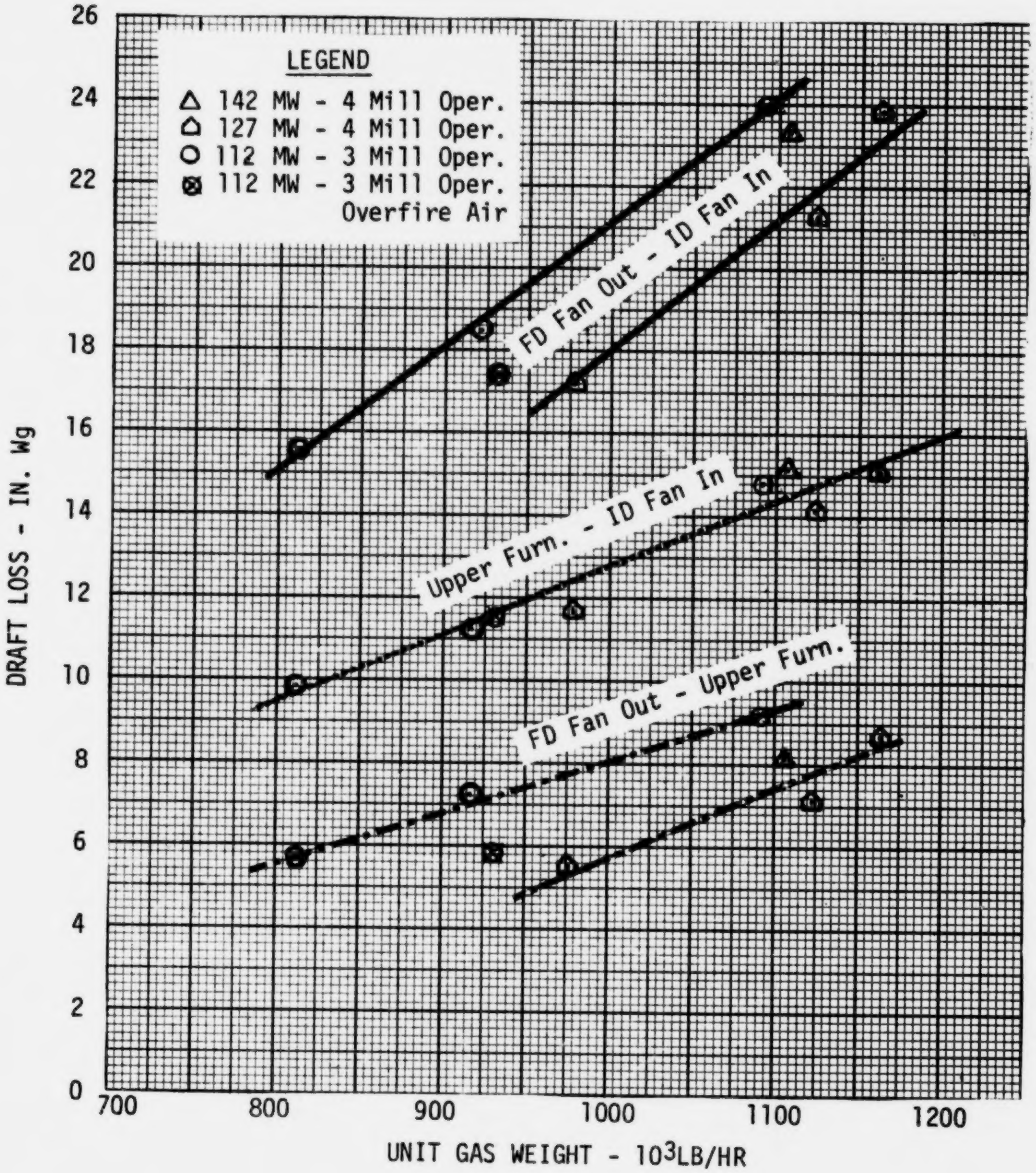


FIGURE 2

NO_x VS. PERCENT EXCESS AIR

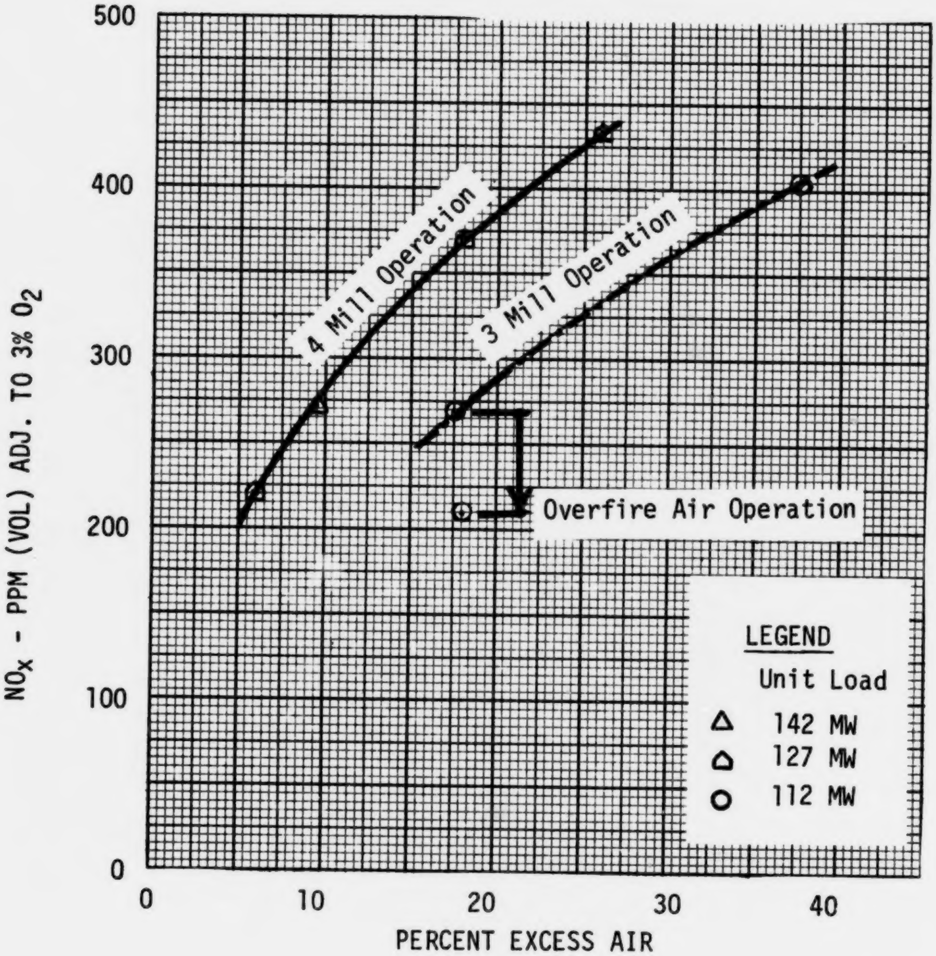
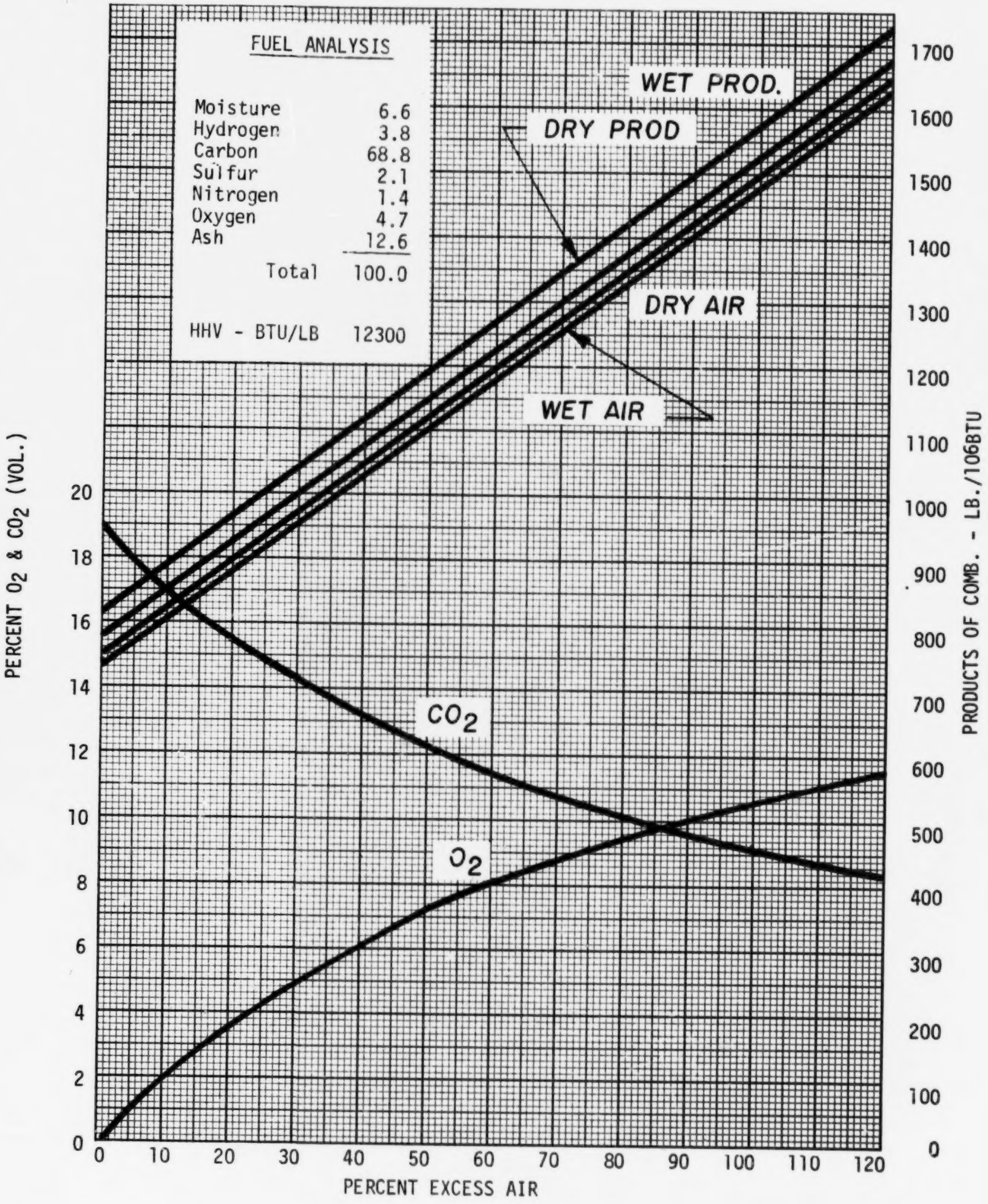


FIGURE 3

COMBUSTION CHARACTERISTICS



FUEL ANALYSIS

Moisture	6.6
Hydrogen	3.8
Carbon	68.8
Sulfur	2.1
Nitrogen	1.4
Oxygen	4.7
Ash	12.6
Total	100.0
HHV - BTU/LB	12300

FIGURE 4

NO$_X$ TEST DATA SUMMARY

TEST NO.			1	2	3	4	5	6	7	8
Purpose of Test			FULL LOAD - % O$_2$ VAR.			MAX. LOAD NORM. OPER.	MAX. 3 MILL LOAD - % O$_2$ VAR. & OVERFIRE AIR			
Date			4/6/72	4/6/72	4/6/72	4/7/72	4/11/72	4/12/72	4/12/72	4/12/72
Load		MW	127	127	126	142	112	112	112	112
Main Steam Flow		10^{3}LB/HR	880	900	900	975	760	770	765	765
% O$_2$ - Economizer Outlet			4.4	3.2	1.2	1.8	5.8	3.1	3.2	1.2
Fuel Elevations in Service			4	4	4	4	3	3	3	3
Nozzle Tilt		DEG.	-14	0	+5	-7	-2	+10	+10	+14
Nozzle Comp. Damper Position - Deg. Open	Aux.		100	100	50	100	0	0	100	0
	"A" Fuel		30	30	30	30	0	0	20	0
	Aux.		100	100	60	100	80	30	80	30
	"B" Fuel		30	30	30	30	30	20	20	20
	Aux.		100	100	80	100	80	80	80	80
	Aux.		100	100	80	100	80	80	80	80
	"C" Fuel		30	30	30	30	30	20	20	20
	Aux.		100	100	80	100	80	70	70	70
	"D" Fuel		30	30	30	30	30	20	20	20
	Aux.		100	100	80	100	80	70	70	70
SHO Temperature		°F	995	985	950	997	992	950	965	915
RHO Temperature		°F	947	945	900	972	927	887	907	860
NO$_x$ Adj. to 3% O$_2$		PPM BY VOL.	433	370	220	271	405	268	209	---
NO$_2$		LB/10^{6}BTU FIRED	.581	.497	.295	.364	.544	.360	.281	---
Unit Efficiency-%			90.9	90.9	91.3	91.5	91.2	91.8	91.4	91.9
Gas Weight		10^{3}LB/HR	1,163.4	1,112.2	978.3	1,106.8	1,091.3	917.8	930.3	812.5

SHEET 1

DRAFT LOSS SUMMARY

	Test No.	1	2	3	4	5	6	7	8
Test Pt.*	Location**				Pressure - In. Wg				
1	"A" FD Fan Out-BD	8.2	6.5	4.8	8.0	8.5	6.5	5.2	5.1
	"B" FD Fan Out-BD	8.2	6.5	5.0	7.4	9.0	7.0	5.5	5.5
2	"B" FD Fan Out-Test	8.6	6.9	5.1	8.2	9.7	7.6	6.3	5.6
3	"A" AH Air Out-BD	2.5	1.8	1.3	2.1	3.0	2.5	1.5	2.0
	"B" AH Air Out-BD	2.2	1.5	1.2	2.1	2.5	2.5	1.3	1.8
	"B" AH Air Out-Test	3.0	1.4	1.3	2.1	3.2	2.0	2.1	1.9
4	D Elev. Left Rear Fuel Air Comp.-Test	.3	-.3	-.6	-.3	.6	-.5	-.5	-1.0
5	A Elev. Left Rear Fuel Air Comp.-Test	.4	-.3	-.5	0	.2	-.6	-.6	-.8
6	Left Mill Air Duct at Windbox-Test	1.9	1.1	.2	1.2	2.7	2.0	1.3	1.6
7	Mill Ar Duct at B-Elev. Mill-Test	1.6	.8	-.2	.8	2.2	1.5	.8	1.1
8	Upper Furn.-BD	-.3	-.37	-.4	-.33	-.45	-.3	-.4	-.4
9	Upper Furn.-Test	-.5	-.6	-.6	-.45	-.45	-.5	-.5	-.4
10	SH Cavity-BD	-1.5	-1.5	-.2	-1.3	-1.3	-1.4	-1.3	-1.2
11	Econ. In.-BD	-5.3	-5.0	-3.8	-5.2	-5.1	-3.7	-4.0	-3.3
12	Econ. Out-Test	-5.6	-5.3	-4.2	-5.9	-5.4	-4.4	-4.4	-3.6
13	"A" AH Gas In-BD	-6.1	-5.5	-4.6	-6.2	-5.7	-4.3	-4.5	-3.9
	"B" AH Gas In-BD	-6.2	-5.7	-4.7	-6.2	-5.8	-4.6	-4.5	-4.1
14	"A" AH Gas Out-BD	-11.1	-9.5	-7.7	-11.1	-10.0	-7.4	-7.7	-6.5
	"B" AH Gas Out-BD	-11.2	-10.2	-8.4	-11.2	-11.8	-8.2	-8.3	-7.3
15	"B" AH Gas Out-Test	-12.4	-11.3	-9.4	-12.4	-11.7	-9.0	-9.4	-7.8
16	"A" ID Fan Suction-BD	-15.2	-14.5	-11.9	-15.2	-15.0	-11.5	-11.9	-9.8
	"B" ID Fan Suction-BD	-16.0	-15.0	-12.7	-16.0	-15.5	-12.0	-12.2	-10.7

*Location Shown on Figure 1
**BD - Board Data
Test - Test Manometer

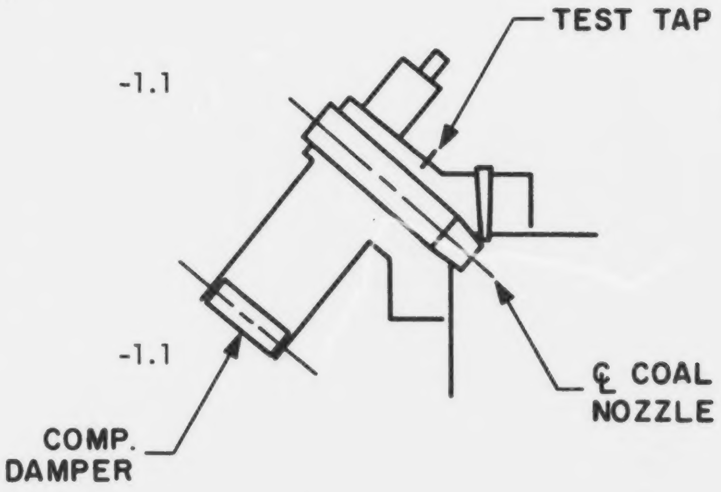
SHEET 2

FUEL AIR COMP. PRESS. VS. COMPARTMENT DAMPER POS.

TEST 4

Fuel Comp.	Damper Pos. - % Open	Comp. Press.-"Wg	Furn. Press "Wg
"A" ELEV.	0	-1.1	-1.1
	20	-.4	
	40	+.4	
	60	+.6	
	80	+1.2	
	100	+1.2	
"D" ELEV.	0	-1.1	-1.1
	20	-.7	
	40	+.5	
	60	+.8	
	80	+1.6	
	100	+1.6	

Typical Fuel Compartment
and
Test Point Arrangement


TEST TAP
℄ COAL NOZZLE
COMP. DAMPER

SHEET 3

BOARD DATA SUMMARY

Test #		1	2	3	4	5	6	7	8
Date		4-6-72	4-6-72	4-6-72	4-7-72	4-11-72	4-12-72	4-12-72	4-12-72
Load-MW		127	127	126	142	112	112	112	112
Main Steam Flow -10^3LB/HR		880	900	900	975	760	770	765	765
RH Flow -10^3LB/HR		800	810	810	860				
Coal Scale Reading-10^3LB/HR		98.5	98.5	98	115	85.5	87.0	86.5	84.5
RH Spray Valve Pos.% Open		20	0	0	0	0	0	0	0
% CO_2		14.6	15.3	15.8	16.1	14.1	15.5	15.2	16.4
Fuel Elev. In Serv.		4	4	4	4	Lwr 3	Lwr 3	Lwr 3	Lwr 3
Ignitor Elev. In Serv.		0	0	0	0	0	0	0	0
Fuel Nozzle-Tilt-Deg. From Horiz.		-14	0	+5	-7	-2	+10	+10	+14
Steam & Water Temp. - F									
SHO	R	1000	980	945	1000	990	945	960	905
	L	990	990	955	995	995	955	970	925
LT SHO	R	835	805	760	825	840	795	810	770
	L	845	820	780	810	850	795	820	770
SH Desup. Out	R	805	800	750	815	830	790	800	760
	L	815	810	770	800	840	790	810	760
RHI		640	638	610	665	630	600	615	575
RHO	R	955	940	900	980	925	880	905	855
	L	940	950	900	965	930	895	910	865
Feedwater		455	455	455	468	445	445	445	445
Econ. Out		490	490	480	495	485	475	475	470
Steam & Water Press.-PSIG									
Feedwater		2000	2000	2000	2000	1990	2000	2000	2000
Drum		1960	1950	1950	1970	1950	1950	1950	1950
SHO		1875	1850	1850	1875	1875	1875	1875	1875
RHI		405	405	405	455	348	350	350	350
RHO		375	375	375	425	321	325	325	325

SHEET 4

BOARD DATA SUMMARY

Test #		1	2	3	4	5	6	7	8
Air & Gas Temp.-F									
AH Air In		122	115	115	115	125	125	115	120
AH Air Out		502	502	502	505	490	485	490	485
AH Gas In		625	615	600	630	610	590	595	580
AH Gas Out		290	295	295	285	270	270	275	275
Air & Gas Press.-"Wg									
FD Fan Out	A	8.2	6.5	4.8	7.0	8.5	6.5	5.2	5.1
	B	8.2	6.5	5.0	7.3	9.0	7.0	5.5	5.5
AH Air Out	A	2.5	1.8	1.3	2.1	3.0	2.5	1.5	2.0
	B	2.2	1.5	1.2	2.1	2.5	2.5	1.3	1.8
Furn.		-.3	-.4	-.4	-.37	-.45	-.3	-.4	-.4
SH Cavity		-1.5	-1.5	-.2	-1.3	-1.3	-1.4	-1.3	-1.2
Econ. In		-5.3	-5.0	-3.8	-5.2	-5.1	-3.7	-4.0	-3.3
Econ. Out	A	-6.1	-5.5	-4.6	-6.2	-5.7	-4.3	-4.5	-3.9
	B	-6.2	-5.7	-4.7	-6.2	-5.8	-4.6	-4.5	-4.1
AH Gas Diff.	A	5.0	4.0	3.1	4.9	4.3	3.1	3.2	2.6
	B	5.0+	4.5	3.7	5.0	5.0	3.6	3.8	3.2
ID Fan In	A	-15.2	-14.5	-11.9	-15.2	-15.0	-11.5	-11.9	-9.8
	B	-16.0	-15.0	-12.7	-16.0	-15.5	-12.0	-12.2	-10.7
Pulv. Air In	A	-1.5	-1.6	-1.5	-1.0	-.6	-.5	-.6	-.5
	B	-1.5	-1.4	-1.3	-.8	-1.0	-1.0	-1.0	-1.2
	C	-1.3	-1.5	-1.4	-1.0	-1.0	-1.0	-1.1	-1.0
	D	-2.7	-3.0	-2.8	-2.3	-2.2	-2.2	-2.4	-2.4
Exh. Air Out	A	9.0	9.0	8.5	9.0	0	0	0	0
	B	12.0	11.0	11.8	12.5	10.5	10.5	10.5	10.5
	C	9.8	10.0	9.3	10.3	9.5	9.5	9.0	8.5
	D	10.8	11.5	10.8	11.2	10.0	10.5	11.0	10.0

SHEET 4A

BOARD DATA SUMMARY

Test #		1	2	3	4	5	6	7	8
FD & ID Fan Perf.									
ID Fan Speed-RPM	A	660	610	550	660	620	540	540	490
	B	650	610	565	650	630	540	550	510
FD Fan Speed-RPM	A	750	655	560	745	775	660	600	580
	B	740	650	580	730	775	680	620	590
ID Fan Damper Pos.-% Open	A	100	100	100	100	100	100	100	100
	B	100	100	100	100	100	100	100	100
FD Fan Damper Pos.-% Open	A	100	100	100	100	100	100	100	100
	B	100	100	100	100	100	100	100	100
ID Fan % Loading 120% Full Scale	A	103	78	65	105	81	60	63	52
	B	104	78	66	105	81	62	65	55
FD Fan % Loading 120% Full Scale	A	86	72	58	86	87	62	65	59
	B	82	70	58	80	87	72	65	60
AH Air Recirc. Damper Pos.-% Open	A	65	65	65	64	64	68	68	68
	B	45	45	45	42	43	47	47	47
Mill Perf.									
Mill Amps	A	35	35	40	44	0	0	0	0
	B	35	38	39	42	42	42	43	43
	C	37	35	40	43	40	41	42	43
	D	39	37	42	42	44	44	43	45
Mill Temp.	A	170	165	165	160	110	100	100	100
	B	165	170	160	160	160	160	160	160
	C	165	170	160	160	170	170	160	160
	D	170	170	165	165	170	170	165	165
% Feeder Cap 120% Full Scale	A	52	50	53	60	0	0	0	0
	B	52	52	54	60	60	60	60	61
	C	47	46	49	60	60	60	60	60
	D	52	52	55	60	60	60	60	61
Exh. Damper Pos-% Open	A	49	49	51	58	0	0	0	0
	B	53	52	55	60	60	60	60	60
	C	48	48	50	60	60	60	60	60
	D	51	52	54	60	60	60	60	61

SHEET 4B

FUEL ANALYSIS

Coal to Feeders

Sample No.		1	2	3
Date Sampled		4-6-72	4-7-72	4-11-72/4-12-72
Total Moisture		6.6	10.1	7.5
Volatile Matter			33.1	27.2
Fixed Carbon			44.1	49.7
Ash			12.7	15.6
Total			100.0	100.0
HHV, Btu/Lb		12300	11280	11710
Moisture		6.6		
Hydrogen		3.8		
Carbon		68.8		
Sulfur		2.1	3.2	1.8
Nitrogen		1.4		
Oxygen		4.7		
Ash		12.6		
Total		100.0		
Ash Fusibility	I.T.	1980°F		
(Reducing Atm.)	S.T.	2320°F		
	F.T.	2530°F		

SECTION VI

ATTACHMENT II

DETAILED TEST PROGRAMS

Two preliminary detailed test programs prepared for this contract are included in this attachment. The first test program is for the evaluation of overfire air, gas recirculation, air preheat and water injection systems and existing process variables. The second test program is limited to evaluation of biased firing, overfire air system and existing process variables. Appendices A,B,C,D and E attached to the first test program apply to both test programs.

PRELIMINARY TEST PROGRAM
CONTRACT NO. 68-02-0264
(C-E CONTRACT 6472)

PILOT FIELD TEST PROGRAM TO STUDY METHODS FOR REDUCTION OF NO_x FORMATION IN TANGENTIALLY COAL FIRED STEAM GENERATING UNITS

PREPARED FOR
THE ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK,
NORTH CAROLINA 27711

JUNE 26,1972
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PROGRAM DESCRIPTION

The test program is designed to investigate the effects of various experimental combustion process modifications on NO_x emission levels from tangentially coal fired utility boilers. The program will be conducted on a boiler specially modified to provide for overfire air, gas recirculation, water injection and air preheat variation in addition to the normally available process variables of excess air, unit loading and air/fuel distribution. The effect of these variables on other emission levels (SO_2, CO, carbon loss, hydrocarbons) will also be monitored. The emission control instrumentation and sampling system are described in Appendix A.

Each combustion process modification will be evaluated separately at steady state operating conditions to establish individual process limitations with respect to effectiveness in reducing NO_x levels, safety, reliability and the effect on unit heat transfer.

The individual process modifications will then be evaluated in various combinations to establish optimum methods of reducing NO_x emission levels. Once the acceptability of the optimized methods is established they will be evaluated with respect to transient and long term operation.

The transient and long term phases of the test program will be repeated with one or two additional coals in addition to the baseline coal to demonstrate the applicability of the experimental results to a variety of coal types.

NO_x CONTROL SYSTEMS

The following combustion process modifications will be possible with the NO_x control systems.

Overfire Air System

The overfire air system will provide for introducing a maximum of 20 percent of the total combustion air above the fuel admission nozzles at full load. The overfire air will enter the furnace tangentially through the top two compartments of the existing windbox as well as two additional compartments in each furnace corner located approximately eight feet above the fuel admission zone. The effect of overfire air will be evaluated at various angles of introduction with respect to the fuel nozzles ($\pm 30°$: vertical plane), velocities and compartment combinations.

Gas Recirculation System

The gas recirculation system will permit recirculating flue gas to the secondary air duct and coal pulverizers either separately or in combination. The system will provide for a maximum of 40% recirculation to the secondary air duct at 80% unit load. The system will permit substituting gas recirculation for hot air to the coal pulverizers while introducing tempering air in the conventional manner.

Air Preheat System

The preheated air temperature entering the secondary air duct will be varied by bypassing the air and/or gas side of the air preheaters to provide the maximum system flexibility.

Water Injection System

Water injection will be admitted into the furnace through two elevations of atomizing spray nozzles located between the top two and bottom two fuel nozzle elevations. A maximum injection rate of 50 pounds per million BTU fired will be used.

Existing Process Variables

Excess air, unit load, and fuel and air distribution will be varied within the current limitations of the existing equipment.

UNIT PERFORMANCE EFFECTS

Operation of the unit as proposed in the experimental study will produce variations in unit operation and thermal performance. The following process measurements are required to properly assess the impact of these changes on new unit design and the retrofiting of existing units.

Furnace Absorption

Recirculating gases to the secondary air compartments and staging of combustion air will effect changes in both peak and average furnace absorption rates. The waterwall absorption rates must therefore be determined to evaluate the impact of variations in average and peak rate and absorption profiles on unit design. Furnace waterwall absorptions will be calculated using chordal drilled TC's as described in Appendix E.

Furnace Corrosion Probes

Unit operation with staged combustion air may result in local reducing atmospheres within the furnace envelope, resulting in accelerated waterwall corrosion rates. To assess the impact of this type of operation on waterwall wastage, furnace corrosion probes will be utilized as described in Appendix D.

Sensible Heat Leaving the Furnace

Variations in furnace heat absorption rates due to modifying the combustion process will result in increasing or decreasing the sensible heat leaving the furnace envelope and entering the superheat and reheat sections of the unit. To determine the sensible heat leaving the furnace, the exit gas temperature will be measured at the vertical furnace outlet plane using water cooled probes as described in Appendix B.

Superheat, Reheat and Economizer Section Absorptions

Variations in the gas temperature and gas flow leaving the furnace envelope and entering the convective sections of the unit will affect the total heat pickup of each section. To assess the impact of modified operation on superheat, reheat and economizer performance, the absorption rates for each section will be determined as described in Appendix B.

Variation in absorption rates may require resurfacing when retrofitting existing units for modified operation.

Air Heater Performance

Air and gas temperatures and gas side oxygen concentrations entering and leaving the air heater are required to calculate air heater performance, unit efficiency, heat losses and air and gas flow rates. These calculations are detailed in Appendix B.

Fuel and Ash Analysis

During each test a representative fuel sample must be obtained for later analysis. The fuel analyses are required to perform combustion calculations necessary to determine excess air levels and unit gas and air flow rates. Pulverized coal fineness samples will be obtained to determine the effect, if any, on furnace wall deposit characteristics.

In addition, coal ash analyses are required to determine ash properties such as base/acid ratios and ash deformation, softening and fluid temperatures necessary for evaluating the furnace wall deposit characteristics of coal fuels. Furnace bottom ash, fly ash and coal pulverizer rejects analyses are also required to determine heat losses and material balances. Analyses procedures are specified in Appendix C.

TEST PROGRAM DESIGN

The test program defining the proposed test sequence is as follows. Due to the experimental nature of this program, it may be necessary to delete or add tests as the individual combustion process modifications are evaluated.

With the exception of the long term and transient operation phases of the program, testing will be conducted at steady state conditions. During each test period, the unit will be allowed to stabilize at the desired test condition after which the required data will be obtained. The stabilized test condition will be maintained for a minimum of one hour.

A. Load Variation and Furnace Wall Deposits

The object of this evaluation is to determine:

1. The effect on the NO_x emission levels of varying load and furnace wall deposits.

2. The maximum allowable furnace wall deposits with respect to steam temperature limits and ash removal system capacities.

Percent Load

Max. Load	L-1
3/4 Max. Load	L-2
1/2 Max. Load	L-3

Furnace Wall Deposits

Clean	D-1
Moderate	D-2
Heavy	D-3

	D-1	D-2	D-3
L-1	5	6	7
L-2		4	
L-3	1	2	3

B. Excess Air and Air Preheat Temperature Variation

The object of this evaluation is to determine:

1. The effect on NO_x emission levels of varying excess air and air preheat temperature.

2. The range of excess air and air preheat temperature variation achievable within the limitations imposed by fan capacities, furnace wall deposits, steam temperatures, and flame stability.

Percent Excess Air

Normal Excess Air	E-1
Minimum Excess Air	E-2
Maximum Excess Air	E-3

Air Preheat Temperature

Normal Air Preheat	H-1
1/2 Minimum Air Preheat	H-2
Minimum Air Preheat	H-3

	E-1	E-2	E-3
H-1	8	10	9
H-2		12	
H-3		11	13

C. Furnace Water Injection Through Existing Oil Guns

The object of this evaluation is to determine:

1. The effect of water injection on furnace gas temperature and NO_x emission levels.

2. The effect of location of water injection on NO_x emission levels.

3. The maximum injection rate with respect to maximum steam outlet temperatures, flame stability, and water source capacity.

Location of Water Injection

Between Lower Two Fuel Nozzles	W-1
Between Upper Two Fuel Nozzles	W-2
Both Locations	W-3

Water Injection Rate

No Injection	I-1
1/2 Maximum Injection	I-2
Maximum Injection	I-3

	W-1	W-2	W-3
I-1	14		
I-2			18
I-3	15	16	17

D. Overfire Air Location, Rate, Velocity and Temperature

The object of this evaluation is to determine:

1. The effect on the NO_x emission level of varying the velocity and height above the fuel compartments at which the overfire air is admitted.

2. The effect on the NO_x emission level of varying the overfire air rate.

3. The maximum overfire air rate with respect to steam temperatures, flame stability and furnace wall deposits.

4. The effect of hot and cold overfire air on the NO_x emission level.

Overfire Air Admisstion Points

Eight Feet Above Fuel Compartments	Top	0-1
	Bottom	0-2
Immediately Above Fuel Compartments	Top	0-3
	Bottom	0-4

Overfire Air Rate and Temperature

No Overfire Air	A-1
1/2 Max. Hot Overfire Air	A-2
Max. Hot Overfire Air	A-3
Max. Cold Overfire Air	A-4

			0-1		0-3	0-1 0-3
	0-1	0-2	0-2	0-2	0-4	0-2 0-4
A-1	19					
A-2			23			28
A-3	20	21	22	25	26	
A-4			24			29

Having established the optimum overfire air location, rate, velocity and temperature, use this condition to perform the following tilt variation tests. In the event that more than one optimum combination is noted, the tilt variation test will be performed with each combination.

E. Overfire Air Tilt Variation

The object of this evaluation is to determine:

1. The effect of tilting overfire air compartment nozzles on the NO_x emission level.

2. If the overfire air compartment nozzles should tilt with the fuel nozzles or remain fixed.

3. The maximum allowable minus and plus tilt with respect to steam temperatures and furnace wall deposits.

Overfire Air Compartment Tilt

Horizontal Tilt	P-1
Maximum Minus Tilt	P-2
Maximum Plus Tilt	P-3

Fuel Nozzle Tilt

Horizontal Tilt	F-1
Maximum Minus Tilt	F-2
Maximum Plus Tilt	F-3

	P-1	P-2	P-3
F-1	30	33	
F-2	31		35
F-3	32	34	

F. Flue Gas Recirculation Location and Rate

The object of this evaluation is to determine:

1. The effect of gas recirculation location and rate on the NO_x emission levels.

2. The most effective means of introducing gas recirculation.

3. The gas recirculation rate required to obtain the maximum reduction in NO_x emission level.

Location of Gas Recirculation

Primary/Auxiliary Air Compartments	G-1
Coal Transport Air	G-2
Auxiliary Air Compartments	G-3
Primary/Auxiliary and Coal Transport Air	G-4
Auxiliary and Coal Transport Air	G-5

Gas Recircualtion Rate

No. Gas Recirculation	B-1
1/2 Max. Gas Recirculation	B-2
Max. Gas Recirculation	B-3

	G-1	G-2	G-3	G-4	G-5
B-1			36		
B-2				43	41
B-3	38	39	37	42	40

Having investigated the effect of location and rate of gas recirculation, the effect of gas recirculation temperature will be studied in the following tests.

G. Flue Gas Recirculation Temperature

The object of this evaluation is to determine:

1. The effect of the temperature of the recirculated gas on the NO_x emission level.

2. The effect of the temperature on the available gas recirculation rate with respect to fan capacities.

Location of Gas Recirculation

Primary/Auxiliary Air Compartments	G-1
Auxiliary Air Compartments	G-3

Gas Recirculation Temperature

Economizer Outlet Temperature	T-1
Air Heater Outlet Temperature	T-2
Econ. Out/AH Out Average Temp.	T-3

	G-1	G-3
T-1	44	
T-2	45	47
T-3	46	

Having established in the preceding tests the most effective overfire air and gas recirculation conditions for reduction of the NO_x emission level, a combination of these overfire air and gas recirculation conditions will be performed in the following tests.

H. Overfire Air and Flue Gas Recirculation Ratio

The object of this evaluation is to determine:

1. The most effective ratio of overfire air and gas recirculation with respect to reducing the NO_x emission level.
2. The effect on overall unit operation

Gas Recirculation Rate

No Gas Recirculation	B-1
1/2 Max. Gas Recirculation	B-2
Max. Gas Recirculation	B-3

Overfire Air Rate

No Overfire Air	A-1
1/2 Max. Overfire Air	A-2
Max. Overfire Air	A-3

	B-1	B-2	B-3
A-1	48		
A-2		51	52
A-3		50	49

Having established the most desirable overfire air/gas recirculation ratio, the boiler will be operated at this condition while the effect of excess air, air preheat, and water injection is investigated.

I. Overfire Air and Gas Recirculation Operation with Low Air Preheat, Low Excess Air and Furnace Injection

The object of this evaluation is to determine:

1. The minimum operating excess air which can be achieved with overfire air and gas recirculation operation and the effect on the NO_x emission level.

2. The effect of low air preheat with gas recirculation and overfire air operation on the NO_x emission level.
3. The effect of furnace water injection with gas recirculation and overfire air on the NO_x emission level.
4. The effect of the above conditions on the overall unit operation.

Percent Excess Air

Normal Excess Air	E-1
Minimum Excess Air	E-2

Air Preheat

Normal Air Preheat	H-1
Minimum Air Preheat	H-3

Water Injection Rate

No Injection	I-1
1/2 Max. Injection	I-2
Max. Injection	I-3

	E-1		E-2	
	H-1	H-3	H-1	H-3
I-1	53	54	57	58
I-2		56		60
I-3		55		59

Having established optimum operating conditions for NO_x reduction use these conditions to perform the following load variation tests.

J. Load Variation At Optimum Conditions

The object of this evaluation is to determine:

1. The effect on the NO_x emission level of operating at previously determined optimum conditions for NO_x reduction while varying load and the degree of furnace wall deposits.
2. The effect on unit operation while operating at said conditions.

Percent Load

Max. Load	L-1
3/4 Max. Load	L-2
1/2 Max. Load	L-3

Furnace Wall Deposits

Clean	D-1
Heavy	D-3

		L-1	L-2	L-3
OC-1	D-1	63	62	61
	D-3	64	65	66

Optimum Conditions

Optimum Conditions	OC-1

K. Effect of Long Term and Transient Operation

After the optimized modes of operation have been established they will be evaluated with respect to their effect on long term and transient unit operation. This evaluation will consist of operating for a one week period at each condition during which time normal unit load changes, etc. would be evaluated.

L. Effect of Coal Change

The long term and transient operation phase of the program will be repeated for one or two additional coals to demonstrate the applicability of the test results to a variety of coal types.

TEST INSTRUMENTATION

The following instrumentation and process measurements will be required in support of the experimental program. These measurements will be obtained in addition to the normally available plant operating instrumentation.

Measurement	Instrument	Location of Measurements
Flue Gas Constituents		
NO_x	Chemiluminescence Analy.	Econ. Gas Outlet and Precipitator Gas Outlet
SO_2	Ultraviolet Analy.	Econ. Gas Outlet and Precipitator Gas Outlet
CO & Hydrocarbons	Infrared Analy.	Econ. Gas Outlet and Precipitator Gas Outlet
Carbon Loss	Dust Collector	Econ. Gas Outlet and Precipitator Gas Outlet
Oxygen	Paramagnetic Analyzer	Econ. Outlet Precipitator Out. Air Heater Inlet & Outlet
Fuel Analysis	ASTM Procedures	Feeder Inlet Coal Pulverizer Outlet Coal
Ash Analysis	ASTM Procedures	Furn. Ash Pit Fly Ash Leaving Econ. Coal Pulverizer Rejects
Flow Rates		
Steam & Water		
Feedwater Flow	Flow Orifice	Econ. Inlet
RH & SH Desuperheat Spray Flow	Heat Balance (°F & PSIG) Around Desuperheater	Desuperheaters
RH Flow	Heat Balance Around Superheat Extractions and Est. Turbine Gland Seal Losses	High Pressure Heaters

Measurement	Instrument	Location of Measurements
Furn. Injection Water Flow	Flow Orifice	Spray Nozzles
Coal Flow	Coal Scale Readings	Coal Feeders
Air & Gas		
Total Air & Gas Wt.	Calculated	As Req'd For Unit Absorption, Combustion Char. and Efficiency Determinations
Gas Recirculation	Pitot Traverse & Oxygen Determination	As Req'd by Ductwork Design
Overfire Air	Pitot Traverse	As Req'd by Duct Work Design
Air Heater Leakage	Paramagnetic O_2 Analyzer	Air Heater Gas Inlet & Outlet Ducts
Temperatures		
Steam & Water °F		
Unit Absorption Rates	Calibrated Stainless Steel C_R-C Well & Button TC's	Econ. Inlet Econ. Outlet SH Desup. In. SH Desup. Out. RH Desup. In. RH Desup. Out. Desup. Spray SH Out. RH Out. HP Heater #5 Inlet Steam " Condensate " FW In " FW Out
WW Absorption	Calibrated Stainless Steel Sheathed C_R-C Chordal W.W. TC's	Waterwall Tubes
Air & Gas °F	C_R-C TC's	Air Heater Air In. " Air Out. " Gas In. " Gas Out. Secondary Air Duct Mill Air Duct Gas Recirculation Duct
	Water Cooled Probes PL/PL-10% R_h TC's	Furnace Outlet Plane

Measurement	Instrument	Location of Measurements
Pressures		
Steam & Water-PSIG		
Unit Absorption Rates	Pressure Gauges and/or Transducers	Econ. Inlet Drum LT SH Out. SH Out. RH In. RH Out. H.P. Heater #5 Shell
Unit Draft Loss	Water Manometers	FD Fan Out, AH Air In. AH Air Out. Windbox Individual Air Comp. Upper Furn. Econ. Outlet AH Gas In AH Gas Out. ID Fan In Gas Recirculation Fan Outlet Gas Recirculation Duct to Sec. Air Duct Junction Gas Recirculation Duct at RH Mill
Temperature and Pressure Logging °F & PSI	C-E Data Logger Capacity: 400 temperatures, 50 pressures	Thermocouples and Pressure Transducers as Req'd by Program

Figure 1. PRELIMINARY TEST PROGRAM

Test No.	Gen. Load	Excess Air %	Nozzle Tilt Deg.	Furnace Wall Condition	Air Preheat Temp.-F	Loc. of Water Inj.	Water Injection Rate	Loc. of Overfire Air
1	1/2 Max.	20	Hor.	Clean	Norm.	---	0	---
2	1/2 Max.	20	Hor.	Mod.	Norm.	---	0	---
3	1/2 Max.	20	Hor.	Heavy	Norm.	---	0	---
4	3/4 Max.	20	Hor.	Mod.	Norm.	---	0	---
5	Max.	20	Hor.	Clean	Norm.	---	0	---
6	Max.	20	Hor.	Mod.	Norm.	---	0	---
7	Max.	20	Hor.	Heavy	Norm.	---	0	---
8	Max.	20	Hor.	Mod.	Norm.	---	0	---
9	Max.	Max.	Hor.	Mod.	Norm.	---	0	---
10	Max.	Min.	Hor.	Mod.	Norm.	---	0	---
11	Max.	Min.	Hor.	Mod.	Min.	---	0	---
12	Max.	Min.	Hor.	Mod.	1/2 Min.	---	0	---
13	Max.	Max.	Hor.	Mod.	Min.	---	0	---
14	Max.	20	Hor.	Mod.	Norm.	Lower	0	---
15	Max.	20	Hor.	Mod.	Norm.	Lower	Max.	---
16	Max.	20	Hor.	Mod.	Norm.	Upper	Max.	---
17	Max.	20	Hor.	Mod.	Norm.	Both	Max.	---
18	Max.	20	Hor.	Mod.	Norm.	Both	1/2 Max.	---
19	Max.	20	Hor.	Mod.	Norm.	---	0	Top-Top
20	Max.	20	Hor.	Mod.	Norm.	---	0	Top-Top
21	Max.	20	Hor.	Mod.	Norm.	---	0	Top-Bot
22	Max.	20	Hor.	Mod.	Norm.	---	0	Top-Top Top-Bot
23	Max.	20	Hor.	Mod.	Norm.	---	0	Top-Top Top-Bot
24	Max.	20	Hor.	Mod.	Norm.	---	0	Top-Top Top-Bot
25	Max.	20	Hor.	Mod.	Norm.	---	0	Bot-Top
26	Max.	20	Hor.	Mod.	Norm.	---	0	Bot-Top Bot-Bot
27	Max.	20	Hor.	Mod.	Norm.	---	0	All
28	Max.	20	Hor.	Mod.	Norm.	---	0	All
29	Max.	20	Hor.	Mod.	Norm.	---	0	All
30	Max.	20	Hor.	Mod.	Norm.	---	0	↕ Opt.
31	Max.	20	Max.-	Mod.	Norm.	---	0	
32	Max.	20	Max.+	Mod.	Norm.	---	0	
33	Max.	20	Hor.	Mod.	Norm.	---	0	
34	Max.	20	Max.+	Mod.	Norm.	---	0	
35	Max.	20	Max.-	Mod.	Norm.	---	0	
36	Max.	20	Hor.	Mod.	Norm.	---	0	---
37	Max.	20	Hor.	Mod.	Norm.	---	0	---
38	Max.	20	Hor.	Mod.	Norm.	---	0	---
39	Max.	20	Hor.	Mod.	Norm.	---	0	---
40	Max.	20	Hor.	Mod.	Norm.	---	0	---
41	Max.	20	Hor.	Mod.	Norm.	---	0	---
42	Max.	20	Hor.	Mod.	Norm.	---	0	---
43	Max.	20	Hor.	Mod.	Norm.	---	0	---
44	Max.	20	Hor.	Mod.	Norm.	---	0	---
45	Max.	20	Hor.	Mod.	Norm.	---	0	---
46	Max.	20	Hor.	Mod.	Norm.	---	0	---
47	Max.	20	Hor.	Mod.	Norm.	---	0	---
48	Max.	20	Hor.	Mod.	Norm.	---	0	↕ Opt.
49	Max.	20	Hor.	Mod.	Norm.	---	0	
50	Max.	20	Hor.	Mod.	Norm.	---	0	
51	Max.	20	Hor.	Mod.	Norm.	---	0	
52	Max.	20	Hor.	Mod.	Norm.	---	0	
53	Max.	20	Hor.	Mod.	Norm.	↕ Opt.	0	↕
54	Max.	20	Hor.	Mod.	Min.		0	
55	Max.	20	Hor.	Mod.	Min.		Max.	
56	Max.	20	Hor.	Mod.	Min.		1/2 Max.	
57	Max.	Min.	Hor.	Mod.	Norm.		0	
58	Max.	Min.	Hor.	Mod.	Min.		0	
59	Max.	Min.	Hor.	Mod.	Min.		Max.	
60	Max.	Min.	Hor.	Mod.	Min.		1/2 Max.	
61	1/2 Max.	Min.	Hor.	Clean	↕	↕ Optimum Conditions	↕	↕
62	3/4 Max.	Min.	Hor.	Clean				
63	Max.	Min.	Hor.	Clean				
64	Max.	Min.	Hor.	Heavy				
65	3/4 Max.	Min.	Hor.	Heavy				
66	1/2 Max.	Min.	Hor.	Heavy				

Figure 1A. PRELIMINARY TEST PROGRAM

Overfire Air Rate	Overfire Air Temp. F	Overfire Air Tilt Deg.	Loc. of Gas Recirc.	Gas Recirc. Rate	Gas Recirc. Temp.-F	Purpose
0	---	---	---	0	---	Load and Furnace Wall Condition Variation
0	---	---	---	0	---	
0	---	---	---	0	---	
0	---	---	---	0	---	
0	---	---	---	0	---	
0	---	---	---	0	---	
0	---	---	---	0	---	
0	---	---	---	0	---	Excess Air and Air Preheat Temperature Variation
0	---	---	---	0	---	
0	---	---	---	0	---	
0	---	---	---	0	---	
0	---	---	---	0	---	
0	---	---	---	0	---	
0	---	---	---	0	---	Water Injection
0	---	---	---	0	---	
0	---	---	---	0	---	
0	---	---	---	0	---	
0	---	---	---	0	---	
0	Hot	---	---	0	---	Overfire Location, Rate and Temperature Variation
Max.	Hot	---	---	0	---	
Max.	Hot	---	---	0	---	
Max.	Hot	---	---	0	---	
1/2 Max.	Hot	---	---	0	---	
Max.	Cold	---	---	0	---	
Max.	Hot	---	---	0	---	
Max.	Hot	---	---	0	---	
Max.	Hot	---	---	0	---	
1/2 Max.	Hot	---	---	0	---	
Max.	Cold	---	---	0	---	
↑	↑	Hor.	---	0	---	Overfire Air Tilt Variation
		Hor.	---	0	---	
		Hor.	---	0	---	
Optimum Conditions						
		Max.-	---	0	---	
		Max.-	---	0	---	
↓	↓	Max.+	---	0	---	
0	---	---	Aux.	0	Econ. Out.	Gas Recirculation Location and Rate Variation
0	---	---	Aux.	Max.	Econ. Out.	
0	---	---	Pri./Aux.	Max.	Econ. Out.	
0	---	---	Coal	Max.	Econ. Out.	
0	---	---	Aux./Coal	Max.	Econ. Out.	
0	---	---	Aux./Coal	1/2 Max.	Econ. Out.	
0	---	---	All	Max.	Econ. Out.	
0	---	---	All	1/2 Max.	Econ. Out.	
0	---	---	Pri./Aux.	Max.	Econ. Out.	Gas Recirculation Temperature Variation
0	---	---	Pri./Aux.	Max.	AH Out.	
0	---	---	Pri./Aux.	Max.	Average	
0	---	---	Aux.	Max.	AH Out.	
0	↑	↑	↑	0	↑	Overfire Air and Gas Recirculation Ratio
Max.				Max.		
Max.	Opt.	Opt.	Opt.	1/2 Max.	Opt.	
1/2 Max.				1/2 Max.		
1/2 Max.	↓	↓	↓	Max.	↓	
↑	↑	↑	↑	↑	↑	Overfire Air and Gas Recirculation with Low Excess Air, Low Air Preheat Temperature and Water Injection
		Optimum Ratio				
↓	↓	↓	↓	↓	↓	
↑	↑	↑	↑	↑	↑	Load and Furnace Wall Condition Variation at Optimum Conditions
		Optimum Conditions				
↓	↓	↓	↓	↓	↓	

APPENDIX A

EMISSION LEVEL DETERMINATION

In order to evaluate the effect of combustion process modifications on boiler emission levels the following instrumentation is proposed.

1. NO_x: Chemiluminescence Analyzer
2. O_2: Paramagnetic Analyzer
3. CO & HC: Nondispersive Infrared Analyzer
4. SO_2: Ultraviolet Analyzer
5. Carbon Loss: ASME Particulate Sampling Train

In addition to these methods of measurement, check methods for NO_x and SO_2 will be performed. These will consist of the PDS chemical analysis for NO_x (ASTM D1608) and the wet chemical titration method for SO_2.

The specifications for the above mentioned emission analyzers are as follows.

NO_x Analyzer

The NO - NO_x Analyzer consists of one (1) control unit, one (1) analyzer unit and one (1) NO_2 to NO convector.

Range: Three ranges 0 - 100 PPM
0 - 1000 PPM
0 - 2000 PPM
Sensitivity: 1 PPM full scale
Reproducibility and accuracy: ± 1 percent full scale
Zero Drift: 1 percent full scale in 24 hours
Span Drift: 2 percent full scale in 24 hours

SO_2 Analyzer

Range: 0 - 1000 PPM
0 - 2000 PPM
0 - 3000 PPM
Accuracy: ± 2 percent full scale
Reproducibility and accuracy: ± 1 percent full scale
Zero and Span Drift: ± 1 percent full scale in 24 hours

APPENDIX A

CO & HC Analyzer

Range: 0 - 100, 0 - 1000 PPM
Accuracy: ± 1 percent full scale
Zero and Span Drift: <1 percent full scale in 24 hours
Sensitivity: 1 percent full scale

O_2 Analyzer

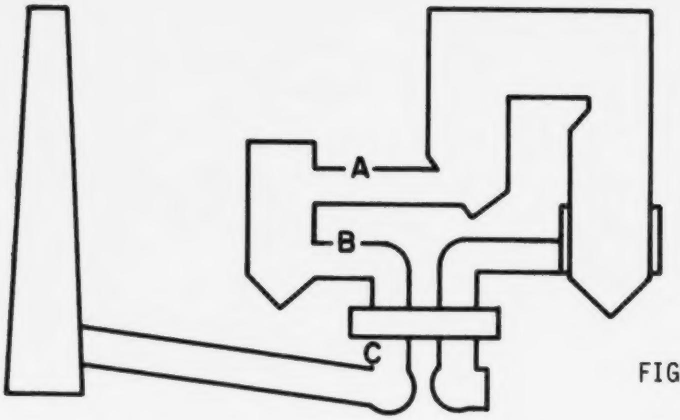
Range: 0 - 10 percent, 0 - 25 percent O_2
Accuracy: ± 1.5 percent full scale
Sensitivity: 0.05 percent O_2

ASME Particulate Sampling Train

The particulate sampling train will consist of necessary sampling probes as described in ASME Test Code PTC 21. Isokinetic samples will be obtained to determine the percent carbon loss in the fly ash.

Probe Locations

A stationary grid of gas sampling probes will be installed at each of three locations as shown in Figure 1.



A. Economizer Outlet
B. Precipitator Outlet
C. Air Heater Outlet

FIGURE 1

The primary sampling location for the determination of NO_x emission levels versus unit operation is the economizer outlet. This location was selected for the following reasons:

1. Elimination of possible air leaks through the precipitator.
2. Elimination of possible additional emissions resulting solely from the electrostatic precipitator operation.

APPENDIX A

Isokinetic dust samples will also be obtained at economizer outlet duct to be analyzed for carbon loss.

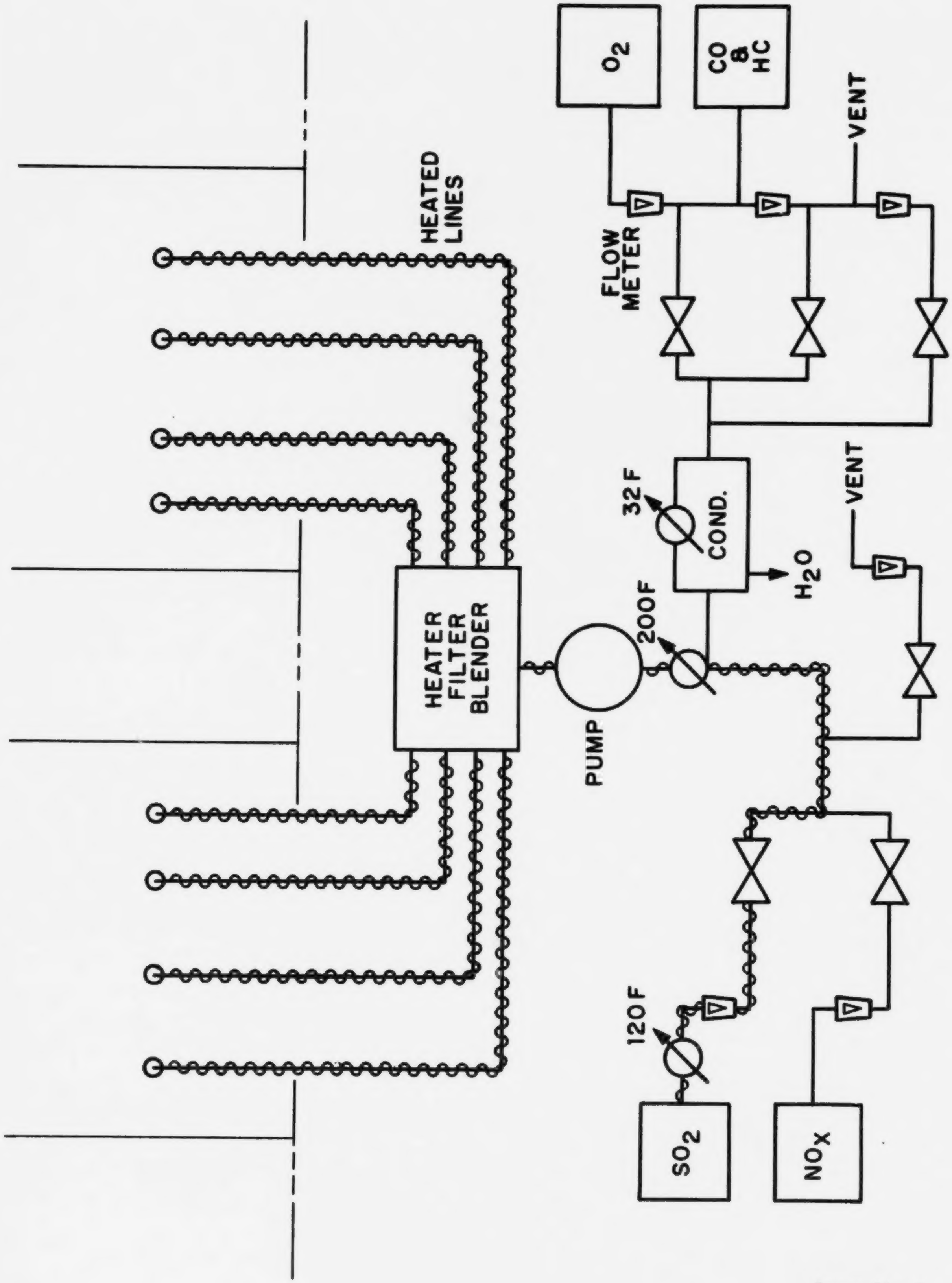
The flue gas will be sampled at the precipitator outlet during selected tests to determine if and how much the precipitator affects the resulting emission levels.

Oxygen levels alone will be determined at the airheater inlet and outlet and the economizer outlet in order to determine the unit efficiency as discussed in Appendix B.

Each sampling grid will consist of four inserts per duct with three depths of probes at each insert giving twenty-four points per duct.

Emission Sampling and Analysis Train

The proposed sampling and analysis train as shown on Figure 2 provides the proper flue gas conditioning to each meter to maintain continuous and simultaneous analysis of emission levels.


HEATED LINES
O2
CO & HC
VENT
FLOW METER
32F
COND.
VENT
H2O
200F
HEATER FILTER BLENDER
PUMP
120F
SO2
NOx

Appendix A
Figure 2

APPENDIX A

Calculations

The analyzers chosen to measure emission levels are directly read in terms of parts per million parts on a volumetric basis. However, it is also necessary to report emissions in terms of LBS per million BTU fired. The following discussion describes the equations involved in a representative conversion when analyzed on a dry basis.

NO_x Conversion PPM (Vol - Dry Basis) to LB $NO_2/10^6$BTU Fired

The values which are needed to make the conversion are:

1. NO_x - PPM Dry Basis Value (NO_x - PPM - D)
2. Percent Oxygen Reading Where NO_x Sample is Taken (% O_2)
3. Complete Fuel Analysis as Fired
    - a. Carbon % by Wt. (C)
    - b. Hydrogen % by Wt. (H)
    - c. Sulfur % by Wt. (S)
    - d. Moisture % by Wt. (M)
    - e. Oxygen % by Wt. (O)
    - f. Nitrogen % by Wt. (N)
    - g. Higher Heating Value of Fuel - BTU/LB (HHV)

For the purpose of simplicity in discussion, the abbreviations in the brackets above will be used in the conversion analysis.

APPENDIX A

VOLUME ADJUSTMENT ON NO_x READINGS

The first step in the conversion involves a volume adjustment on the measured NO_x value. This adjustment is based on a 3 percent by volume of oxygen in the flue gas as related to the 21 percent by volume of oxygen in the air. All of the NO_x samples or readings must be adjusted in this manner in order to account for dilution.

Mathematically the adjustment takes the form:

$$NO_x\text{-PPM-D}_{\text{Adj. to } 3\%\ O_2} = \left[\frac{21-3}{21-(\%\ O_2)}\right] (NO_x\text{-PPM-D})$$

CALCULATING THE TOTAL MOLES OF DRY PRODUCTS OF COMBUSTION AT STOICHIOMETRIC CONDITIONS

Calculating to obtain the moles of oxygen which are needed at stoichiometric conditions, we get:

$$1. \quad \left\{\begin{array}{l}\text{Moles of } O_2\\ \text{Needed at}\\ \text{Stoichiometric}\\ \text{Combustion}\end{array}\right\} = \left[\frac{(C)}{12} + \frac{(H)}{4} + \frac{(S)}{32} - \frac{(O)}{32}\right] /100$$

Since all the oxygen reacts with the constituents of the fuel, it is no longer present as free oxygen, therefore, we can use the moles of oxygen needed at stoichiometric conditions to obtain the moles of nitrogen entered into the products with the oxygen. The ratio of nitrogen to oxygen in air by volume is 79.05/20.95.

Therefore:

$$2. \quad \left\{\begin{array}{l}\text{Moles of } N_2 \text{ Entered}\\ \text{Into the Products of}\\ \text{Combustion with } O_2 \text{ at}\\ \text{Stoichiometric Conditions}\end{array}\right\} = \left[\frac{79.05}{20.95}\right] \left\{\begin{array}{l}\text{Moles of } O_2 \text{ Needed}\\ \text{at Stoichiometric}\\ \text{Combustion}\end{array}\right\}$$

Now we must calculate for the total moles of dry products at stoichiometric conditions, this can be done by adding the moles of CO_2, SO_2 and N_2 from the combustion process to the results of equation 2.

$$3.\quad \left\{\begin{array}{l}\text{Total Moles of}\\ \text{Dry Products at}\\ \text{Stoichiometric}\\ \text{Conditions}\end{array}\right\} = \left\{\begin{array}{l}\text{Moles of } N_2 \text{ Entered}\\ \text{Into the Products of}\\ \text{Combustion with } O_2 \text{ at}\\ \text{Stoichiometric Condi-}\\ \text{tions}\end{array}\right\} + \left[\frac{(C)}{12} + \frac{(S)}{32} + \frac{(N)}{28}\right]/100$$

MOLES OF AIR NEEDED TO PROVIDE A 3% EXCESS OF OXYGEN

Because the NO_x-PPM value is adjusted to a base of 3% excess oxygen, we must provide an excess of air, in terms of moles, to the dry products of combustion to obtain the total moles of dry products at 3% excess oxygen.

if: y = total moles of dry products of combustion at stoichiometric combustion.

and: x = moles of air needed to provide a 3% excess of oxygen in the flue gas.

then: $.03(y + x) = .2095\,x$

Algebraically we obtain:

$$x = \frac{.03(y)}{.1795}$$

$$4.\quad \left\{\begin{array}{l}\text{Total Moles of Dry}\\ \text{Products of Combus-}\\ \text{tion at a 3\% Excess}\\ \text{of Oxygen}\end{array}\right\} = Z = x + y$$

CONVERSION EQUATION

The final step in the conversion NO_x-PPM to Lbs. $NO_2/10^6$BTU Fired is:

$$\text{Lbs. } NO_2/10^6\text{BTU Fired} = \left[\frac{Z}{HHV}\right]\left[NO_x\text{-PPM-D}_{\text{Adj. to 3\% } O_2}\right]\left[46\right]$$

In Terms of Units:

Where: Lbs. = (moles)(molecular wt.)

and: $$\frac{\text{Moles}}{\text{106 Moles}} = \frac{\text{Parts}}{\text{106 Parts}}$$

$$\text{Lbs. } NO_2/10^6\text{BTU} = \left[\frac{\text{Moles of Dry Prods./Lb Fuel}}{\text{BTU/Lb Fuel}}\right]\left[\frac{\text{Moles } NO_x}{10^6 \text{ Moles of Dry Prods.}}\right]\left[\begin{array}{l}\text{Molecular}\\ \text{Wt. of}\\ NO_2\end{array}\right]$$

$$= \text{Lbs. } NO_2/10^6\text{BTU}$$

Example Calculation for dry values of NO_x-PPM:

Known Values:

1. NO_x-PPM Dry Basis = 500 PPM
2. Percent Oxygen Reading Where NO_x Sample is Taken = 4% O_2
3. Complete Fuel Analysis as fired
    - a. Carbon % By Wt. = 43.5
    - b. Hydrogen % By Wt. = 3.2
    - c. Sulfur % By Wt. = 0.8
    - d. Moisture % By Wt. = 29.4
    - e. Oxygen % By Wt. = 11.8
    - f. Nitrogen % By Wt. = 0.8
    - g. Higher Heat Value = 7490Btu/Lb

$$NO_x\text{-PPM Dry Adj. to } 3\%\ O_2 = \left[\frac{21-3}{21-(\%O_2)}\right]\left[NO_x\text{-PPM}_{\text{Dry}}\right]$$

$$= \left[\frac{18}{21-4\%\ O_2}\right](500)$$

$$= 529 \text{ PPM}$$

APPENDIX A

y = total moles of dry products @ stoichiometric conditions.

$$y = \left[\frac{79.05}{20.95}\right]\left[\frac{(C)}{12} + \frac{(H)}{4} + \frac{(S)}{32} - \frac{(O)}{32}\right]/100 + \left[\frac{(C)}{12} + \frac{(S)}{32} + \frac{(N)}{28}\right]/100$$

$$y = \left[\frac{79.05}{20.95}\right]\left[\frac{43.5}{12} + \frac{3.2}{4} + \frac{0.8}{32} - \frac{11.8}{32}\right]/100 + \left[\frac{43.5}{12} + \frac{.8}{32} + \frac{.8}{28}\right]/100$$

$\underline{y = .1908}$

x = moles of air needed to provide a 3% excess of oxygen.

$$x = \frac{.03y}{.1795} = \frac{(.03)(.1908)}{.1795}$$

$\underline{x = .032}$

z = total moles of dry products at a 3% excess of oxygen.

$z = x + y$

$z = .032 + .1908$

$\underline{z = .223}$

$$\text{Lbs. } NO_2/10^6\text{BTU} = \left[\frac{Z}{HHV}\right](NO_x\text{-PPM}_{\text{Dry Adj. to 3\% } O_2})\ (46)$$

$$\text{Lbs. } NO_2/10^6\text{BTU} = \left[\frac{.223}{7490}\right](529)(46)$$

$$\boxed{\text{Lbs. } NO_2/10^6\text{BTU} = .7259}$$

EXPLANATION FOR RUNNING PROGRAM LBS NOX G.E. MARK I BASIC

1. Call Mark I computer and sign-on in the basic system.
2. Call Program LBSNOX
3. Input data in lines 10 thru 99 in the form.

APPENDIX A

```
10 DATA N
20 DATA C, H2, S, M, O2, N2, H
30 DATA P1, P2, P3,.........Pn
```

Where:

N = The number of dry adjusted NO_x-PPM values to be converted to lbs $NO_2/10^6$BTU.

C = Carbon % By Wt., in fuel.

H2 = Hydrogen % By Wt., in fuel.

S = Sulfur % By Wt., in fuel.

M = Moisture % By Wt., in fuel.

O2 = Oxygen % By Wt., in fuel.

N2 = Nitrogen % By Wt., in fuel.

H = Higher heating value of fuel in BTU/Lb.

P = NO_x-PPM Dry (Adj. to 3% O_2)

On the following page is a listing of the program LBSNOX and an example run.

APPENDIX A

```
LBSNOX    8:47  20 THU 02/24/72

10 DATA 18
20 DATA 85.85,10.8,2.415,.02,.5,.325,18265
30 DATA 243,169,274,185,198,162,161,179,220
40 DATA 167,201,186,177,292,264,268,162,161
100 DIM P(50)
110 PRINT "NOX-PPM","NO2-LBS./10↑6 BTU"
120 READ N
130 READ C,H2,S,M,O2,N2,H
140 LET Y1=((79.05/20.95)*((C/12)+(H2/4)+(S/32)-(O2/32)))/100
150 LET Y=Y1+((C/12)+(S/32)+(N2/28))/100
160 LET X=(.03*Y)/(.1795)
170 LET Z=X+Y
180 FOR I=1 TO N
190 READ P(I),
200 LET L=(Z/H)*(P(I))*46
210 PRINT P(I),L
220 NEXT I
230 STOP
240 END


RUN

LBSNOX    8:48  20 THU 02/24/72

NOX-PPM         NO2-LBS./10↑6 BTU
 243             .318919
 169             .2218
 274             .359604
 185             .242798
 198             .25986
 162             .212613
 161             .2113
 179             .234924
 220             .288733
 167             .219175
 201             .263797
 186             .244111
 177             .232299
 292             .383228
 264             .34648
 268             .35173
 162             .212613
 161             .2113
```

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APPENDIX B

STEAM GENERATOR THERMAL PERFORMANCE

In order to evaluate overall steam generator thermal performance as affected by the various methods of NO_x reduction under consideration the following test instrumentation will be installed.

Furnace Outlet Gas Temperature

Three 30 foot water cooled, aspirated, platinum-platinum 10 percent rhodium thermocouple probes in the vertical outlet plane.

Economizer Outlet, Air Heater Gas Inlet and Air Heater Gas Outlet

A stationary grid of combination thermocouple and gas sampling probes will be installed at each of the above locations. The gas samples will be passed through a multipoint sampler and into a paramagnetic oxygen analyzer for average O_2 determination at each location. Each grid will consist of four probes per duct (each probe three penetrations deep) for a total of twenty-four probes.

Flows

Feedwater flow will be determined by differential measurement across the flow orifice. Superheat and reheat spray flow and reheat flow will be determined by heat balance.

Draft Losses

Static pressure measuring probes and inclined manometers will be used to determine draft losses on all components.

Steam and Water Temperatures

Calibrated CR/C well and button thermocouples will be used to determine fluid temperature entering and leaving each convection section.

APPENDIX B

Steam and Water Pressures

Calibrated transducers or pressure gauges will be used to determine fluid pressures entering and leaving each convection section.

Location of Test Points

1. Furnace Outlet Gas Temperature (3 probes)
2. Gas Temperature and Analysis

   Gas leaving Econ. - 4 probes per duct (each probe three penetrations deep)

   Gas entering AH - 4 probes per duct (each probe three penetrations deep)

   Gas leaving AH - 4 probes per duct (each probe three penetrations deep)
3. Air Temperature entering AH - 4 probes per duct
4. Air and Gas Pressures - Manometer

   Air Heater Air Inlet

   Air Heater Air Outlet

   Windbox

   Individual Air Compartment

   Upper Furnace

   Economizer Outlet

   Air Heater Gas Inlet

   Air Heater Gas Outlet

   ID Fan Inlet

   Gas Recirculation Fan Duct at Secondary Air Duct Junction

   Gas Recirculation Duct at Mill Air Duct Junction

   Gas Recirculation Fan Outlet

APPENDIX B

5. Steam and Water Temperatures - Well or Button Thermocouples

   Economizer Inlet - 1

   Economizer Outlet - 2

   SH DESH Inlet - 2

   SH DESH Outlet - 2

   SH Outlet - 2

   RH before DESH - 2

   RH after DESH - 2

   RH Outlet - 2

   DESH Spray - 1

   FW entering HP Heater #5 - 1

   FW leaving HP Heater #5 - 1

   Steam to HP Heater #5 - 1

   Drain from HP Heater #5 - 1

6. Steam and Water Pressures - Calibrated Transducers or Gages

   Economizer Inlet

   Drum

   LTSH Outlet

   SH Outlet

   RH Inlet

   RH Outlet

   Spray Water Source

   HP Heater #5 Shell

7. Flow Nozzle Measurements - Differential Manometers

   FW Flow Nozzle

Calculations and Flows

Boiler Efficiency and Products of Combustion

Boiler test efficiency calculations will be performed as shown in

APPENDIX B

Section B. Combustion calculations performed on a per million BTU fired basis and air and gas flow calculations are shown in Section A.

Flows (Refer to flow schematic, Figure 1)

Feedwater Flow Rate

A general equation for the calculation of fluid flow rates is given in the following reference text: "Fluid Meters - Their Theory and Application", page 65, equation 112, ASME Research Committee on Fluid Meters, Fifth Edition, 1959.

$$W_1 = 359.0 \frac{C}{\sqrt{1 - B^4}} Y_1 d^2 \sqrt{\gamma_1 h_w}$$

where W_1, fluid rate of flow LBS/HR

C, meter discharge coefficient

$B = d/D$ = throat diameter/approach diameter

Y_1, compressibility factor

γ_1, specific weight of fluid, LB/FT^3

h_w, meter head differential, IN H_2O @ 68°F

For the calculation of liquid flow rates at varying temperatures the thermal expansion factor, F_A, must be introduced into the above equation; with $Y_1 = 1$ for liquids we have:

$$W_1 = 359.0 \frac{C}{\sqrt{1 - B^4}} F_A d^2 \sqrt{\gamma_1 h_w}$$

Superheat Spray Flow

$$W_s = W_1 \left[\frac{h_1 - h_2}{h_2 - h_s}\right]$$

W_s is superheat desuperheating spray flow, LBS/HR.

W_1 is flow entering desuperheater, LBS/HR. This is feedwater flow where there is no blowdown or steam extracted from the drum.

h_1 is enthalpy of steam entering desuperheater, BTU/LB.

h_2 is enthalpy of steam leaving desuperheater, BTU/LB.

h_s is enthalpy of desuperheating water, BTU/LB.

Main Steam Flow

$$W_2 = W_1 + W_s$$

W_2 is main steam flow, LB/HR.

Reheat Flow

$$W_4 = W_3 + W_{RS}$$

W_4 is reheater steam flow, LBS/HR

W_3 is steam flow entering reheat desuperheater, LBS/HR.

W_{RS} is reheat desuperheating spray flow, LBS/HR (Calc. to follow).

A. $W_3 = W_2 - W_H - W_L$

W_2 is main steam flow (previously calculated).

W_H is final HP heater steam flow (calculation per Item B).

W_L is HP turbine leakage (from manufacturer's data - figure 2) LBS/HR.

B. HP Heater Extraction Steam

$$W_H = W_1 \left[\frac{h_{n2} - h_{n1}}{h_e - h_d} \right]$$

W_1 is feedwater flow (previously calculated).

h_n2 is enthalpy of feedwater leaving heater BTU/LB.

h_n1 is enthalpy of feedwater entering heater BTU/LB.

h_e is enthalpy of steam entering heater BTU/LB.

h_d is enthalpy of drain from heater BTU/LB.

C. Reheat Spray Flow (if any)

$$W_{RS} = W_3 \left[\frac{h_3 - h_4}{h_4 - h_{RS}} \right]$$

W_{RS} is reheat desuperheat spray flow LBS/HR.

W_3 is steam flow entering desuperheater.

h_3 is enthalpy steam entering desuperheater, BTU/LB.

h_4 is enthalpy steam leaving desuperheater, BTU/LB.

h_{RS} is enthalpy desuperheating water, BTU/LB.

therefore

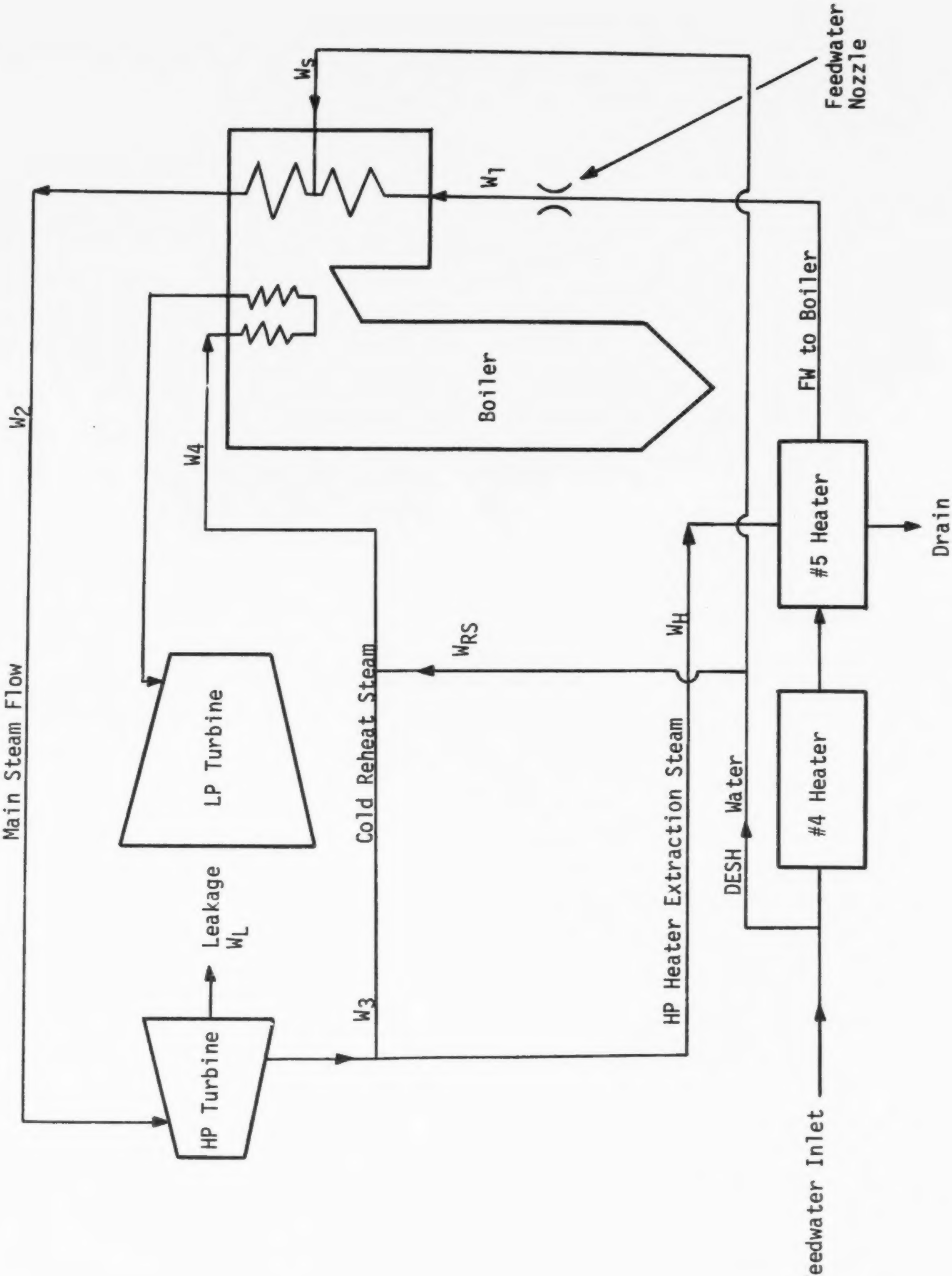
$$W_4 = W_3 + W_{RS}$$

W_4 is reheater steam flow.

W_3 is steam flow entering reheat desuperheater.

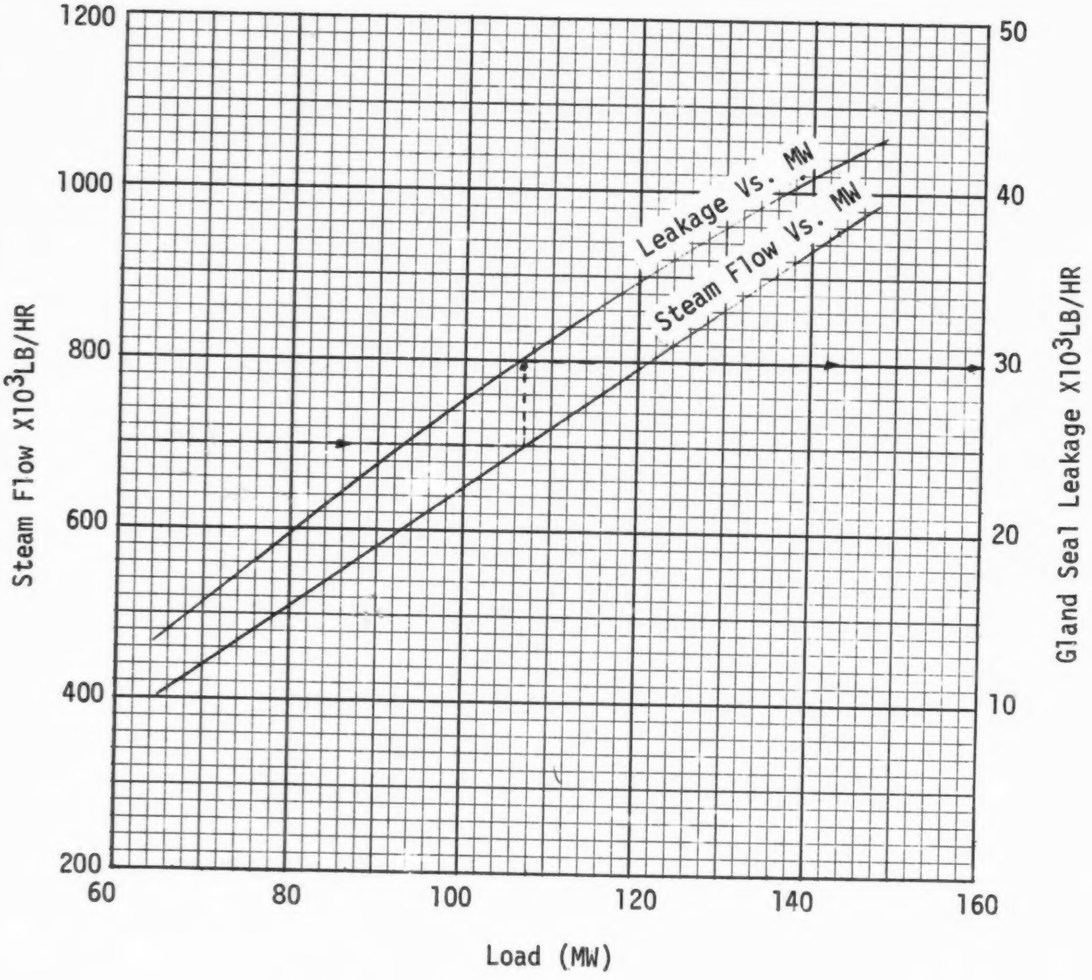
W_{RS} is reheat spray flow.

FLOW SCHEMATIC


Main Steam Flow
W_2
HP Turbine
Leakage
W_L
LP Turbine
W_3
Cold Reheat Steam
W_4
W_{RS}
Boiler
W_S
W_1
Feedwater Nozzle
HP Heater Extraction Steam
W_H
DESH Water
#4 Heater
#5 Heater
FW to Boiler
Drain
Feedwater Inlet

APPENDIX B
FIGURE 1

TURBINE GLAND SEAL LEAKAGE



APPENDIX B
FIGURE 2

APPENDIX B
SECTION A

SAMPLE CALCULATION OF COMBUSTION CHARACTERISTICS AND GAS AND AIR FLOWS

1. ULTIMATE COAL ANALYSIS

Carbon - 61.3%
Hydrogen- 4.3%
Nitrogen- 1.5%
Oxygen - 7.1%
Sulfur - 3.7%
Moisture- 7.5%
Ash - 14.6%
TOTAL 100.0%

HHV = 11,160 BTU/LB

2. THEORETICAL DRY AIR, TDA

$$TDA = \left[\frac{11.54\ (\%\ C) + 34.34\ (\%\ H - \frac{\%\ O}{8}) + 4.32\ (\%\ S)}{HHV \times 10^6}\right] \times 10^4$$

Where: 11.54 = LBS Air to Burn One Lb. C
34.34 = LBS Air to Burn One Lb. H
4.32 = LBS Air to Burn One Lb. S

$$TDA = \left[\frac{11.54\ (61.3) + 34.34\ (4.3 - \frac{7.1}{8}) + 4.32\ (3.7)}{11{,}160 \times 10^6}\right] \times 10^4$$

$TDA = 753.20\ LB/10^6 BTU$

3. MOISTURE IN AIR, MA

$MA = .013\ (TDA)$

Where: .013 = Standard Specific Humidity

$MA = .013\ (753.20) = 9.79\ LB/10^6 BTU$

4. THEORETICAL WET AIR, TWA

$TWA = TDA + MA$

$TWA = 753.20 + 9.79 = 762.99\ LB/10^6 BTU$

5. FUEL IN PRODUCTS, F

$$F = \frac{(100 - \%\ Ash - \%\ SCL)}{HHV \times 10^6}$$

Where: % SCL = CL (HHV, Fuel/14,450)

$$F = \frac{(100 - 14.6 - .2)}{11{,}160 \times 10^6} \times 10^4 = 76.34\ LB/10^6 BTU$$

6. MOISTURE FROM FUEL, MF

$$MF = \frac{(\%\ Moisture) + 9\ (\%\ H)}{HHV\ X\ 10^6}\ X\ 10^4$$

Where: 9 = LB Moisture Formed by Burning 1 LB Hydrogen

$$MF = \frac{(7.5) + 9\ (4.3)}{11{,}160\ X\ 10^6}\ X\ 10^4 = 41.40\ LB/10^6BTU$$

7. GAS FLOWS ENTERING AIRHEATER AT 13.9% EXCESS AIR

A. - Dry Air, DA

$$DA = \left[1 + \frac{\%\ Excess\ Air}{100}\right](TDA)\ (K)$$

Where: K = 1 - (% SCL/100)

$$DA = \left[1 + \frac{13.9}{100}\right](753.20)\ (.998) = 856.17\ LB/10^6BTU$$

DA (Flow) = DA (Heat Input From Fuel)

DA (Flow) = 856.17 (2138.7) = 1831.4 X 10^3LB/HR

B. Moisture In Air, MA

MA = .013 (DA)

MA = .013 (856.17) = 11.13 LB/10^6BTU

C. Wet Air, WA

WA = DA + MA

WA = 856.17 + 11.13 = 867.30 LB/10^6BTU

WA (Flow) = WA (Heat Input From Fuel)

WA (Flow) = 867.30 (2138.7) = 1855.3 X 10^3 LB/HR

D. Wet Products, WP

WP = F + WA

WP = 76.34 + 867.30 = 943.64 LB/10^6BTU

WP (Flow) = WP (Heat Input From Fuel)

WP (Flow) = 943.64 (2138.7) = 2018.5 X 10^3 LB/HR

E. Dry Products , DP

$DP = WP - MA - MF$

$DP = 943.64 - 11.13 - 41.40 = 891.11$ LB/10^6BTU

DP (Flow) = DP (Heat Input From Fuel)

DP (Flow) = 891.11 (2138.7) = 1906.2 X 10^3LB/HR

8. GAS FLOWS LEAVING AIRHEATER AT 22.6 % EXCESS AIR

A. Dry Air, DA

$$DA = \left[1 + \frac{\%\ \text{Excess Air}}{100}\right](TDA)(K)$$

$$DA = \left[1 + \frac{22.6}{100}\right](753.20)(.998) = 921.58\ \text{LB}/10^6\text{BTU}$$

DA (Flow) = DA (Heat Input From Fuel)

DA (Flow) = 921.58 (2138.7) = 1970.8 X 10^3 LB/HR

B. Moisture in Air, MA

$MA = .013\ (DA)$

$MA = .013\ (921.58) = 11.98$ LB/10^6BTU

C. Wet Air, WA

$WA = DA + MA$

$WA = 921.58 + 11.98 = 933.56$ LB/10^6BTU

WA (Flow) = WA (Heat Input From Fuel)

WA (Flow) = 933.56 (2138.7) = 1996.5 X 10^3LB/HR

D. Wet Products, WP

$WP = F + WA$

$WP = 76.34 + 933.56 = 1009.90$ LB/10^6BTU

WP (Flow) = WP (Heat Input From Fuel)

WP (Flow) = 1009.90 (2138.7) = 2159.9 X 10^3LB/HR

E. Dry Products, DP

DP = WP - MA - MF

DP 1009.90 - 11.98 - 41.40 = 956.52 LB/10^6BTU

DP (Flow) = DP (Heat Input From Fuel)

DP (Flow) = 956.52 (2138.7) = 2045.7 X 10^3LB/HR

SAMPLE CALCULATION OF EFFICIENCY - HEAT LOSSES METHOD

1. DRY GAS LOSS, DGL

$\text{DGL} = (\text{DP Lvg. AH})(.24)(T_{GL} - T_{AE}) \times 10^{-4}$

Where: .24 = Instantaneous Specific Heat of Dry Products
T_{GL} = Temperature of Gas Lvg. AH
T_{AE} = Temperature of Air Ent. AH
DP Lvg. AH = Dry Products Lvg. AH

$\text{DGL} = (956.52)(.24)(265 - 96) \times 10^{-4}$

DGL = 3.88%

2. MOISTURE IN AIR LOSS, MAL

$\text{MAL} = (.013)(\text{DA Lvg. AH})(.46)(T_{GL} - T_{AE}) \times 10^{-4}$

Where: .013 = Standard Specific Humidity
.46 = Instantaneous Specific Heat of Water Vapor
DA Lvg. AH = Dry Air in Products Lvg. AH

$\text{MAL} = (.013)(921.58)(.46)(265 - 96) \times 10^{-4}$

MAL = .09%

3. MOISTURE FROM FUEL LOSS, MFL

$\text{MFL} = \text{MF}\left[1089 - T_{AE} + .46\,(T_{GL})\right] \times 10^{-4}$

Where: $\left[1089 - T_{AE} + .46\,(T_{GL})\right]$ Accounts for Evaporating & Superheating the Moisture In & From the Fuel.

$\text{MFL} = 41.40\left[1089 - 96 + .46\,(265)\right]$ X 10-4

MFL = 4.62%

4. CARBON HEAT LOSS, CL

$$\text{CL} = \frac{\%\ \text{Ash}}{100\% - \%\ \text{Carbon in Fly Ash}}\left[\frac{\%\ \text{Carbon in Fly Ash}\ (14{,}450)}{\text{HHV, Fuel}}\right]$$

Where: 14,450 = HHV of Carbon

$$\text{CL} = \frac{14.6}{100 - 1.4}\left[\frac{1.4\ (14{,}450)}{11160}\right]$$

CL = .27%

5. RADIATION LOSS, RL

Determined From ABMA Curve.

RL = .22%

6. HEAT LOSS IN FLYASH, FAL

$$FAL = \frac{\%\ ASH}{HHV}(.22)(T_{GL} - T_{AE})$$

Where: .22 = Specific Heat of Fly Ash

$$FAL = \frac{14.6}{11160}(.22)(265 - 95)$$

FAL = .05%

7. ASH PIT LOSS, APL

Determined using curves on figure 1 and 2.

① Furnace Width, Feet -40.167

② Furnace Depth,Feet -40.167

③ Furnace Diagonal, Feet -57.0

④ Furnace Height, Feet -114.83

⑤ Distance Firing ℄ to Hopper Aperture Feet -49.66

⑥ Ratio⑤/③-.87

⑦ Ashpit Aperture (Area), Feet^2 -100.42

⑧ Ratio⑦/③④-.015

⑨ Curve Value of Radiation Thru Aperture (% Heat Loss) - .23

⑩. % Ash in Fuel, As Fired -14.6

⑪. HHV Fuel, as Fired, BTU/LB - 11160

⑫. ⑩ (10^4)/⑪, Ash Fired/10^6BTU -13.08

⑬. % Ash Fired Going to Ashpit -0

⑭. Slagging or Dry Ash Bottom ? - Dry Ash

⑮. Curve ValueSensible and Latent Heat of Ash (% Heat Loss) -0

⑯. Total Ash Pit Loss =⑨+ ⑮ = .23 + 0 = .23%

8. REJECT LOSS, RL

$$RL = \text{LB/HR Rejected} \left(\frac{\text{HHV, Rejects}}{\text{Total BTU/HR Input}}\right) \times 10^2$$

Where: Total BTU/HR Input is Estimated Using $\left[\text{Unit Absorption} \times 1.11\right]$

$$RL = 3495 \left(\frac{5650}{2151.7 \times 10^6}\right) \times 10^2$$

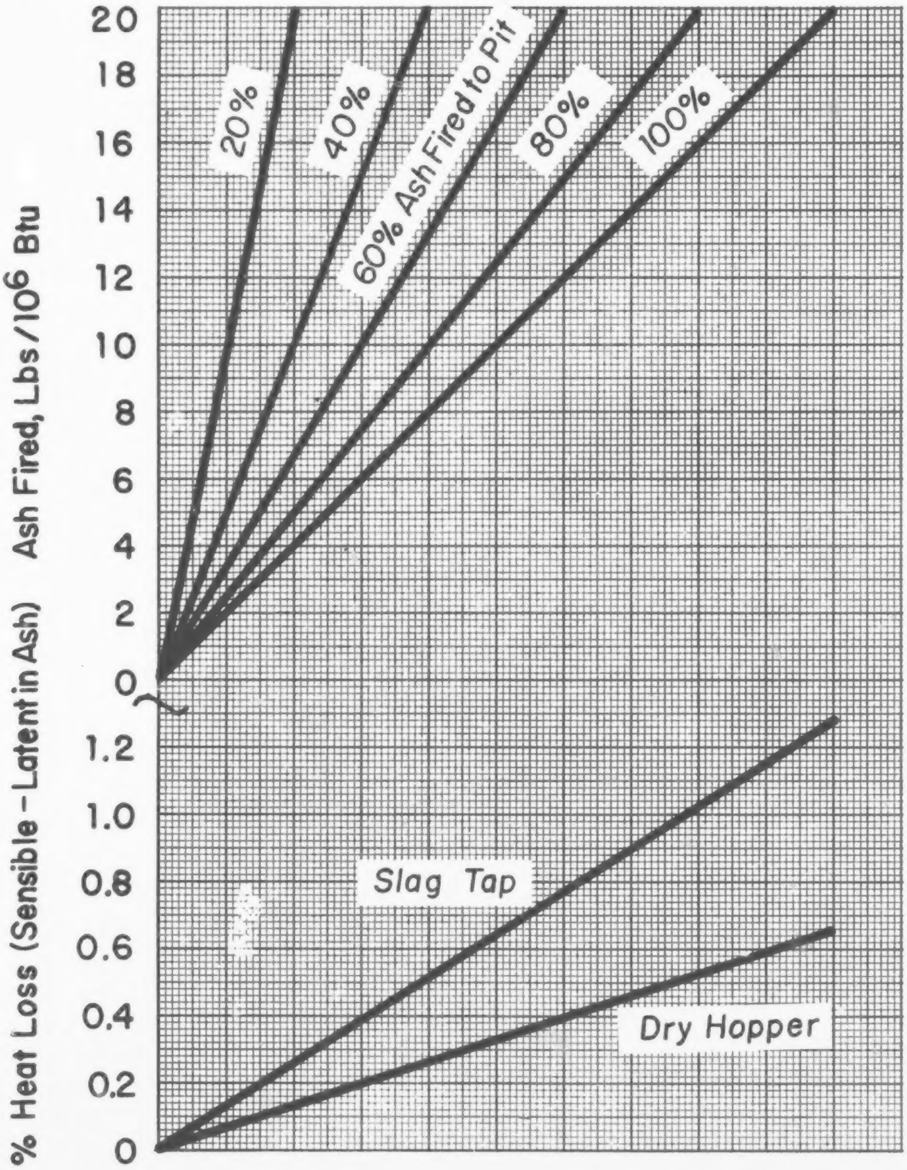
RL = .92%

ASHPIT HEAT LOSS CORRELATION

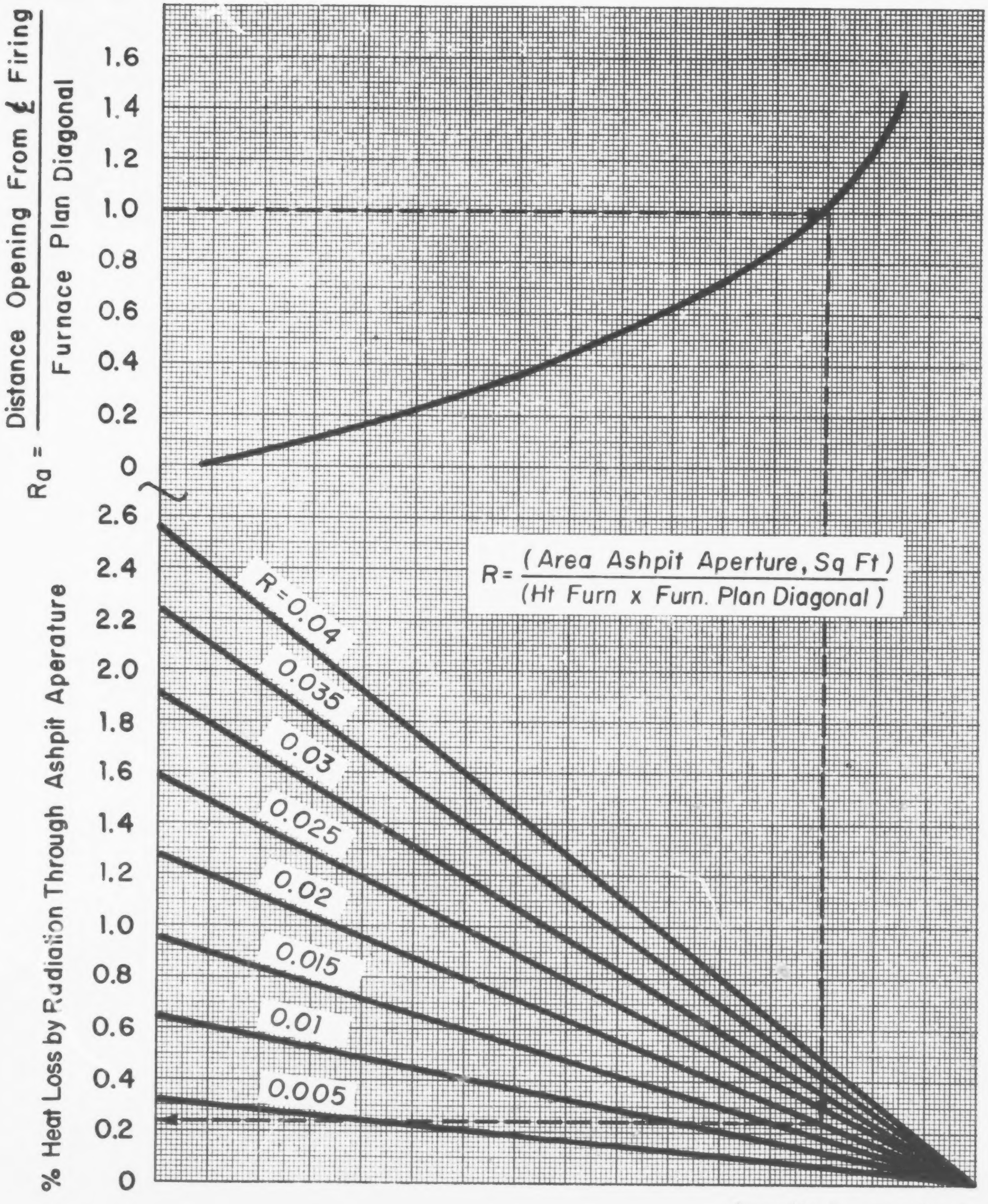
(H. D. MUMPER)

1. Furnace Width, Feet
2. Furnace Depth, Feet
3. Furnace Diagonal, Feet
   (Only one divided Furnace)
4. Furnace Height, Feet
5. Distance Firing ℄ to Hopper Aperture, Ft.
6. Ratio (5) / (3)
7. Ashpit Aperture: Width, Ft
   Depth, Ft
   Area, Ft^2
8. Ratio (7) / (3) (4)
9. Curve Value of Radiation thru Aperture
   (% Heat Loss)
10. % Ash in Fuel, as Fired
11. HHV Fuel, as Fired, BTU/#
12. (10) x 10^4 / (11), Ash Fired/10^6BTU
13. % Ash Fired going to Ashpit, %
14. Slagging or "dry ash" bottom?
15. Curve Value Sensible & Latent Heat
    of Ash, % Heat Fired.
16. TOTAL ASH PIT LOSS = (9) + (15)

NOTE any special circumstances, such as;
- a. Water spray nozzles above surface of water pool and whether they are angled up toward aperture.
- b. Lack of water sluice in ashpit.
- c. Other.



Appendix B - Section B
Figure 1



Appendix B - Section B
Figure 2

APPENDIX C

COAL & ASH ANALYSES

Coal and ash sampling and analyses will be performed essentially in accordance with the following ASTM procedures.

ASTM Specification	Title
D-271-70	Sampling and Laboratory Analysis of Coal and Coke
D-2013-68	Samples, Coal, Preparing for Analysis
D-410-38	Sieve Analysis of Coal
D-311-30	Sieve Analysis of Crushed Bituminous Coal
D-2015-66	Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter
D-409-71	Grindability of Coal by the Hardgrove-Machine Method
D-1857-68	Fusibility of Coal Ash
D-2795-69	Analysis of Coal and Coke Ash

APPENDIX D

EVALUATION OF CORROSION POTENTIAL

In order to evaluate whether operating a boiler with low excess air or staged combustion will result in localized reducing atmospheres and what effect these conditions will have on waterwall tube wastage the follow instrumentation will be used. Basically the test involves exposing a metal coupon held at WW metal temperatures to lower furnace conditions for a finite time period. At the end of this time period the coupon will be evaluated for weight loss and visual evidence of attack. Ash deposits will also be collected using the probe and will be subjected to evaluation in terms of corrosion potential as well as furnace slagging.

Alkali-metal sulfates have normally been recognized as the aggressive compounds in water-wall tube wastage. The first step in the overall corrosion mechanism involves transport of the alkalies to tube surfaces. Alkalies, as they exist in coal mineral matter, are to a large degree sublimated and carried to tube surfaces as a vapor where they condense. Here they combine with sulfur oxides to form alkali sulfates. One possibility is that with low excess air, iron pyrites may be deposited on tube surfaces without undergoing significant oxidation. Oxidation of the pyrites would then occur at the tube surface providing sufficient sulfur oxides to react with alkalies forming either pyrosulfates or alkali-iron-trisulfates. In addition the required high localized levels of SO_3 would be produced to maintain stability of the alkali-iron-trisulfates.

Another possibility, although less likely than the previous mechanism, is that free sulfur from deposited pyrites can attack iron directly. This is not too likely because enamel deposits (alkalies) will usually shield the tube from sulfur attack.

APPENDIX D

The quantity and distribution of pyrites in the subject coal will have an influence on the behavior of the sulfur in the furnace. Coal containing pyrites that are not well disseminated throughout the coal would be more likely to result in coarse particles reaching the tubes. In cases such as this particular attention should be given to coal fineness and flame impingement.

DESCRIPTION OF EQUIPMENT AND INSTRUMENTATION

The most reliable method of evaluating corrosive potential in a boiler is by exposing a sample of tube metal for a finite period of time and measuring the resulting weight loss. This can be accomplished by using a probe to insert the metal coupon into the furnace and maintain it at the desired temperature. Figure 1 depicts the type of probe and coupon that will be used to obtain such information. This particular probe utilizes air to keep the coupon at the desired temperature.

Typical instrumentation to automically maintain the desired temperature would consist of an electronic controller , and a pneumatic controller. The pneumatic controller operates as a switching device, using solenoid valves, to regulate the amount of cooling air going to the probe. The amount of air is based on a signal from the electronic controller which is tied in to the sensing thermocouple at the probe coupon.

PROBE LOCATION IN FURNACE

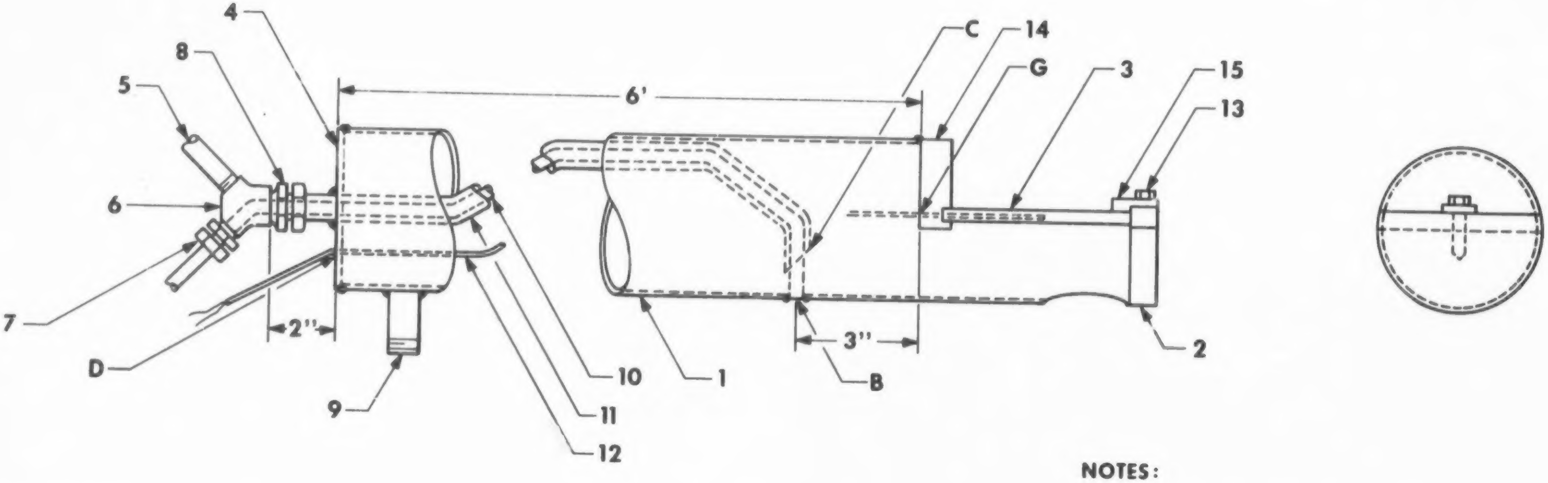
The ideal location of the probe would be in the furnace fuel and air nozzle zone located centrally from both a vertical and horizontal standpoint. One probe should be installed in each of two furnace walls.

EVALUATION OF DATA

It is extremely important that the rate of weight loss measured during the test period is not assumed to hold throughout much longer time periods. Tube wastage is not usually linear with respect to time; a higher rate of wastage quite often occuring during periods of initial operation.

In order to interpret corrosion potential, a control case will be utilized. The control case will involve exposure of a similar type of metal coupon for the time period equal to the test period using the same coal under conventional firing conditions.

Coupon weight losses from the two modes of boiler operation will be compared in terms of weight loss as well as visual inspection. Deposits collected from each case will be carefully analyzed to determine differences in composition. Deposit compositions will be evaluated with respect to coupon weight loss in each case and mechanisms of corrosion postulated if applicable.



ITEM No.	No. RQD.	DESCRIPTION	MATERIAL SPECIFICATIONS
1	1	PROBE BODY	1 1/2" DIA. × 6' LONG SCHEDULE 40 CARBON STEEL
2	1	END PLATE	1 1/2" DIA. × 1/4" 304 STOCK
3	20	CORROSION COUPONS	1 1/2" × 3 1/4" × 3/16" THICK 192 CARBON ST.
4	1	REAR PLATE	1 1/2" ROUND PLATE × 1/8" THICK
5	1	AIR QUENCHING PIPE	1/4" PIPE
6	1	PIPE "T"	3/8" PIPE 45°
7	1	GAS SAMPLING FITTING	3/8" PIPE To 1/8" TUBING
8	1	QUENCHING TUBE FITTING	3/8" PIPE To 3/8" TUBING
9	1	PROBE COOLING INLET	1/2" PIPE NIPPLE 3" LONG
10	1	GAS SAMPLING TUBE	1/8" × .020 WALL 304 SS TUBE 7' LONG
11	1	GAS QUENCHING TUBE	3/8" × .020 WALL 304 SS TUBE 7' LONG
12	2	SS SHEATHED TC	1/16" DIA. × 7' LONG CR C TC
13	20	MACHINE SCREWS	8—32 MACHINE SCREWS
14	1	FRONT PLATE	1 1/2" O.D. × 5/16" THICK CARBON STEEL
15	1	CLAMP	5/16" × 5/16" × 3/4" 304

NOTES:

A. HELIARC ALL POINTS MARKED ◆

B. DRILL 5/32" HOLE and HELIARC TUBE To PROBE

C. CUT QUENCHING TUBE END ON 45° ANGLE

D. SILVER SOLDER TC'S IN END PLATE

E. DRILL THRU SWAGELOC FITTING, ITEM No. 7 for CLEARANCE of 1/8" TUBING

F. DRILL THRU SWAGELOCK FITTING ITEM No. 8 for CLEARANCE of 3/8" TUBING

G. SILVER SOLDER TC'S To FRONT PLATE

NOTE:

PRELIMINARY DESIGN

PROBE ASSEMBLY

APPENDIX D—FIGURE 1

APPENDIX E

WATERWALL ABSORPTION MEASUREMENT AND CALCULATION

In order to determine waterwall absorption rates the following test instrumentation is required,

Chordal drilled thermocouples are installed as shown on Sheets 3 and 4 to obtain waterwall absorption. The depth of the thermocouple below the surface of the tube depends on the tube diameter. The following tabulation lists typical thermocouple junction depths:

Tube O.D.	Depth of TC
1 1/4"	.048"
1 1/2"	.047"
1 3/4"	.046"
2"	.045"
2 1/4"	.044"
2 1/2"	.043"

Lists of properties of hot finished and cold drawn tubes are tabulated on Sheets 5 thru 9.

CALCULATION OF HEAT FLUX FROM CHORDAL DRILLED THERMOCOUPLE FOR SUB-CRITICAL PRESSURE

The following is a description for determining the crown heat flux with sub-critical pressure.

D_o = outside tube diameter, nominal

L = avg. wall thickness at metal surface

D_M = mean tube diameter = $D_i + L$

D_i = inside tube diameter = $D_o - 2L$

D_p = diameter of thermocouple location

K = metal conductivity

APPENDIX E

1. Metal ΔT_M

$$\Delta T_M = (Q/A)\frac{D_o L}{D_M K}$$ = metal temperature drop from crown to inside diameter.

But, since the thermocouple is not at the crown the measured temperature is at some location, P. Therefore, P must be determined, either graphically or by measurement. Then:

$$\Delta T'_M = (Q/A)'\frac{D_p L}{D_M K}$$ = metal temperature drop from thermocouple to inside diameter.

2. Film ΔT_f (by Jens & Lottes)

$$\Delta T_f = \frac{60 \left[(Q/A)''/10^6\right]^{0.25}}{e^{(p/900)}}$$

But, since $(Q/A)''$ is the heat flux at the inside diameter and we are interested, at the moment, in the heat flux at location P, the film temperature drop becomes

$$\Delta T_f = \frac{60 \left[(D_p/Di)(Q/A)'/10^6\right]^{0.25}}{e^{(p/900)}}$$

where $(Q/A)'' = (D_p/D_i)(Q/A)'$

3. Overall $\Delta T'_o$

$$\Delta T'_o = T'_M + \Delta T_f$$

$$\Delta T'_o = (Q/A)'\frac{D_p L'}{D_M K} + \frac{60 \left[(D_p/D_i)(Q/A)'/10^6\right]^{0.25}}{e^{(p/900)}}$$

$\Delta T'_o$ = thermocouple temperature - saturation temperature

This now tells us that for a given tube size, tube material and pressure a $(Q/A)'$ will result in one $\Delta T'_o$. Or, conversely, a measured thermocouple temperature will yield one heat flux. In order to convert $(Q/A)'$, the flux at the TC, to (Q/A), the flux at the crown, we assume radial heat flow and decrease $(Q/A)'$ by a ratio of diameters. Thus:

$Q/A = (D_p/D_o)(Q/A)'$

APPENDIX E

METHOD OF TEST SET-UP

The pattern for test instrumentation on the furace walls consists of a vertical column of thermocouples near the center of the front and right side wall. Three horizontal rows of thermocouples are located in and slightly above the burner zone at elevations of expected peak absorption. The center horizontal row extends to the rear and left side walls also. Locations of the chordal thermocouples are shown on Sheet 2.

A method of calibrating the installed thermocouples has been devised to check on the uniformity of the TC's. The unit is "bottled up" with all vents closed (superheater, drum, etc.) and all air dampers shut and circulating pumps running. Each thermocouple reading should then approach an average temperature. Any TC which does not read within one or two degress of the average should be adjusted.

PLOTTING TEST DATA

The absorption rates measured on the vertical column of thermocouples are plotted on a graph vs. furnace elevation; using test average readings on oil and gas fired units, and peak rates for coal fired units. A smoothly faired curve is then drawn through these points giving a test vertical profile of the center tube.

The test average absorption rates in the horizontal rows are averaged and these averages are then plotted on the same graph as the vertical profile. Another vertical profile is now drawn through these horizontal average rates having a shape similar to the center tube vertical profile. This is now considered the average absorption profile for the furnace and assumes that the horizontal averages form the same general contour as the test vertical profile for the center tube. See Sheet 1.

APPENDIX E

FURNACE HEAT ABSORPTION (Calculated & Measured)

The measured furnace absorption is compared to the calculated furnace absorption to check on the validity of our test data with the idea in mind that our horizontal strip averages will have to be adjusted if the measured does not compare to our calculated.

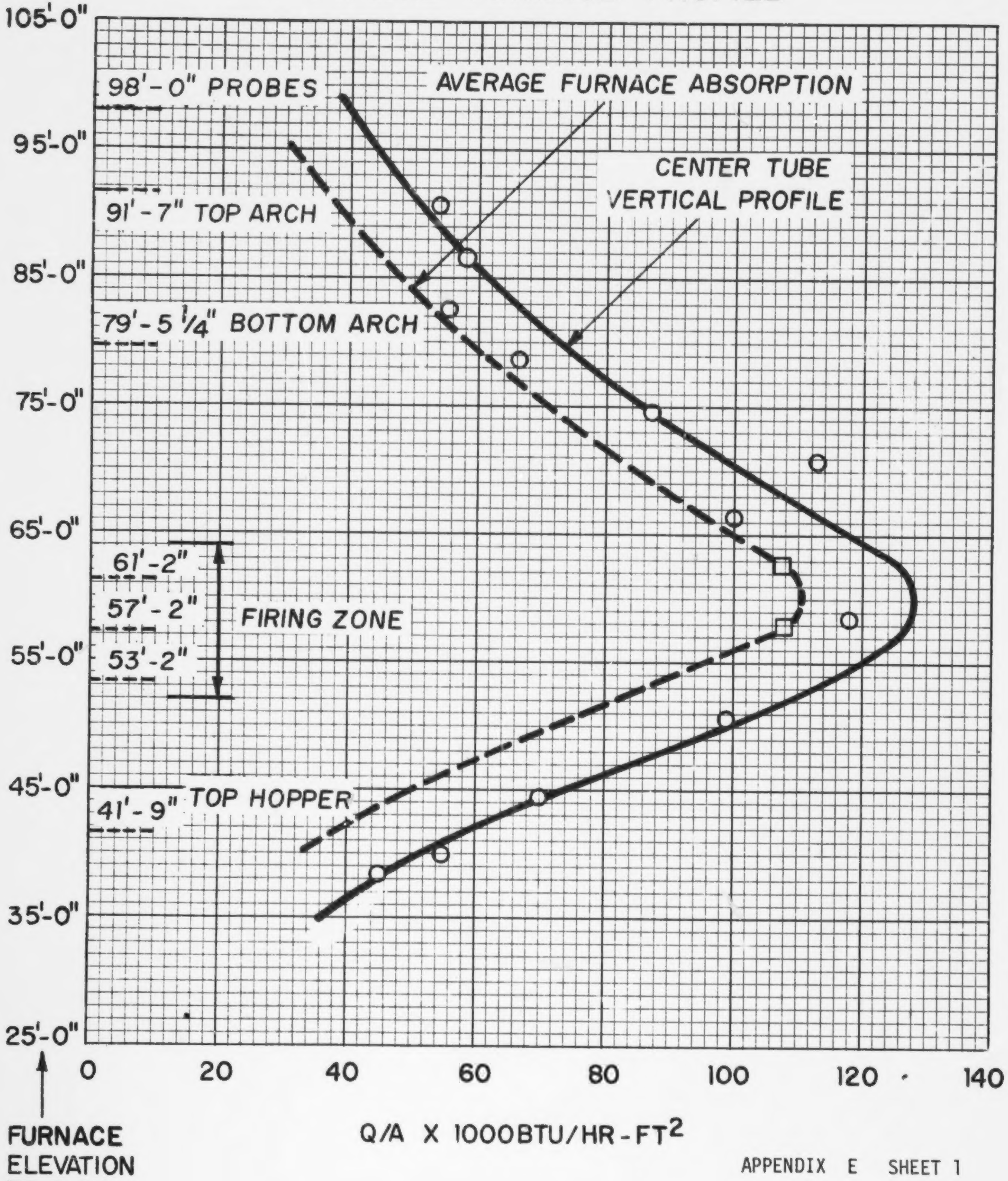
The calculated furnace heat absorption is equal to the net heat input minus the sensible heat in the gas at the furnace outlet, minus the radiant heat leaving the furnace.

$$Q_{calc} = NHI - Q_{sensible\ heat} - Q_{radiation}$$

The $Q_{sensible\ heat}$ used in the above equation is found from the furnace outlet temperature.

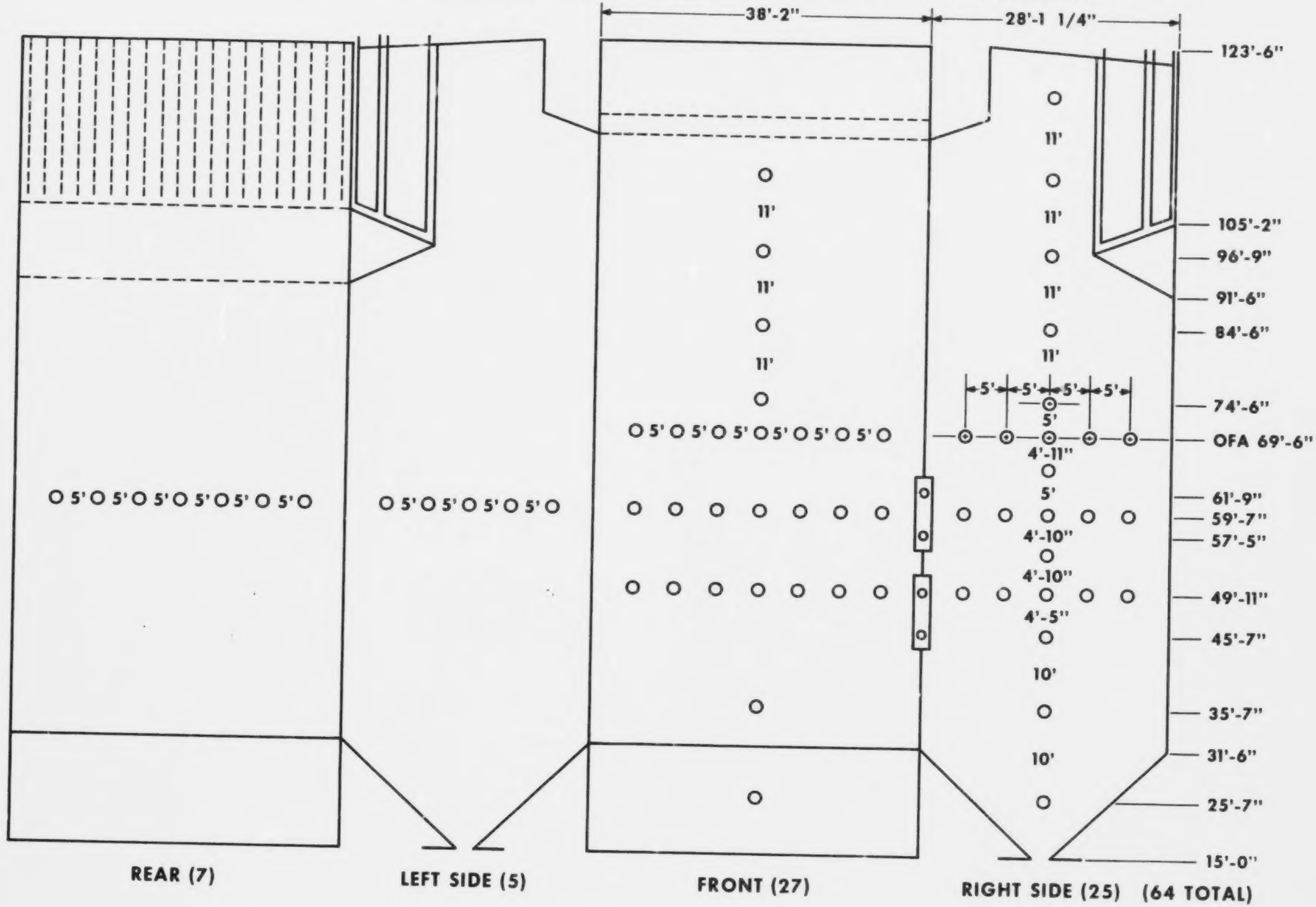
The measured furnace heat absorption is found from the area under the furnace absorption profile either by means of a planimeter or integration.

TYPICAL FURNACE PROFILE



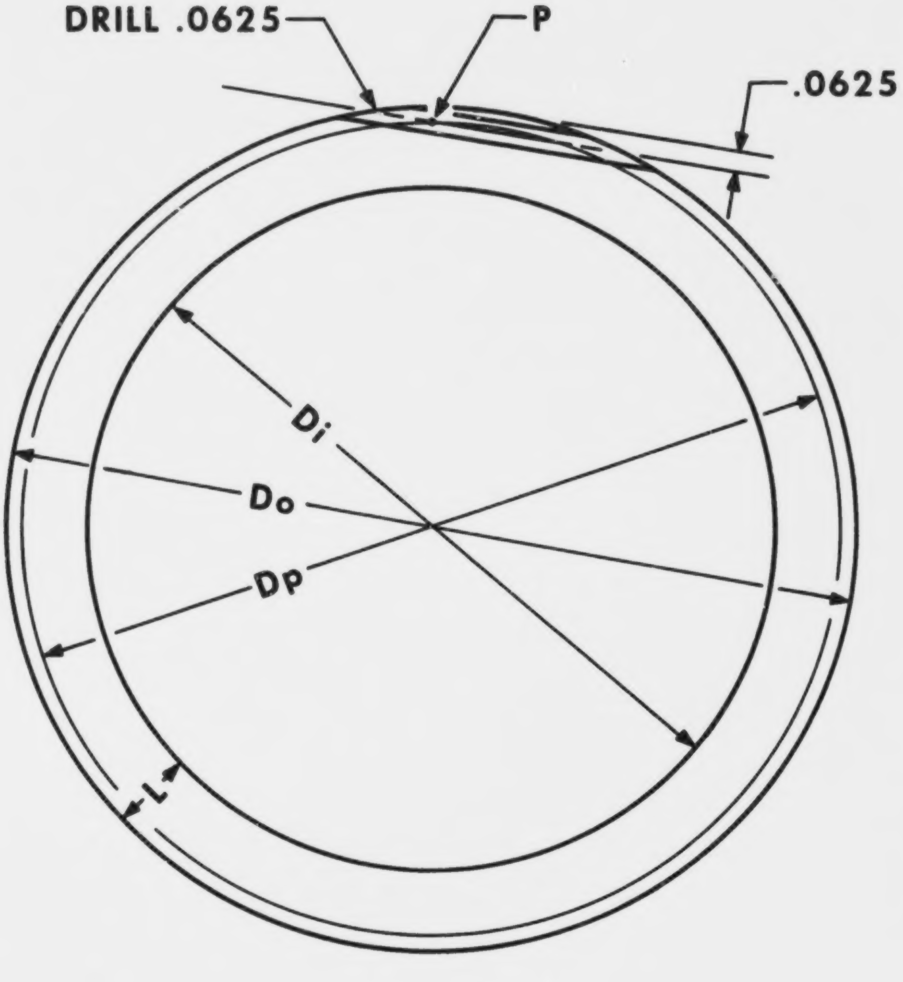
APPENDIX E SHEET 1

CHORDAL THERMOCOUPLE LOCATIONS ON THE FURNACE WATERWALLS


38'-2"
28'-1 1/4"
123'-6"
105'-2"
96'-9"
91'-6"
84'-6"
74'-6"
OFA 69'-6"
61'-9"
59'-7"
57'-5"
49'-11"
45'-7"
35'-7"
31'-6"
25'-7"
15'-0"
11'
5'
4'-11"
4'-10"
4'-5"
10'
REAR (7)
LEFT SIDE (5)
FRONT (27)
RIGHT SIDE (25)
(64 TOTAL)

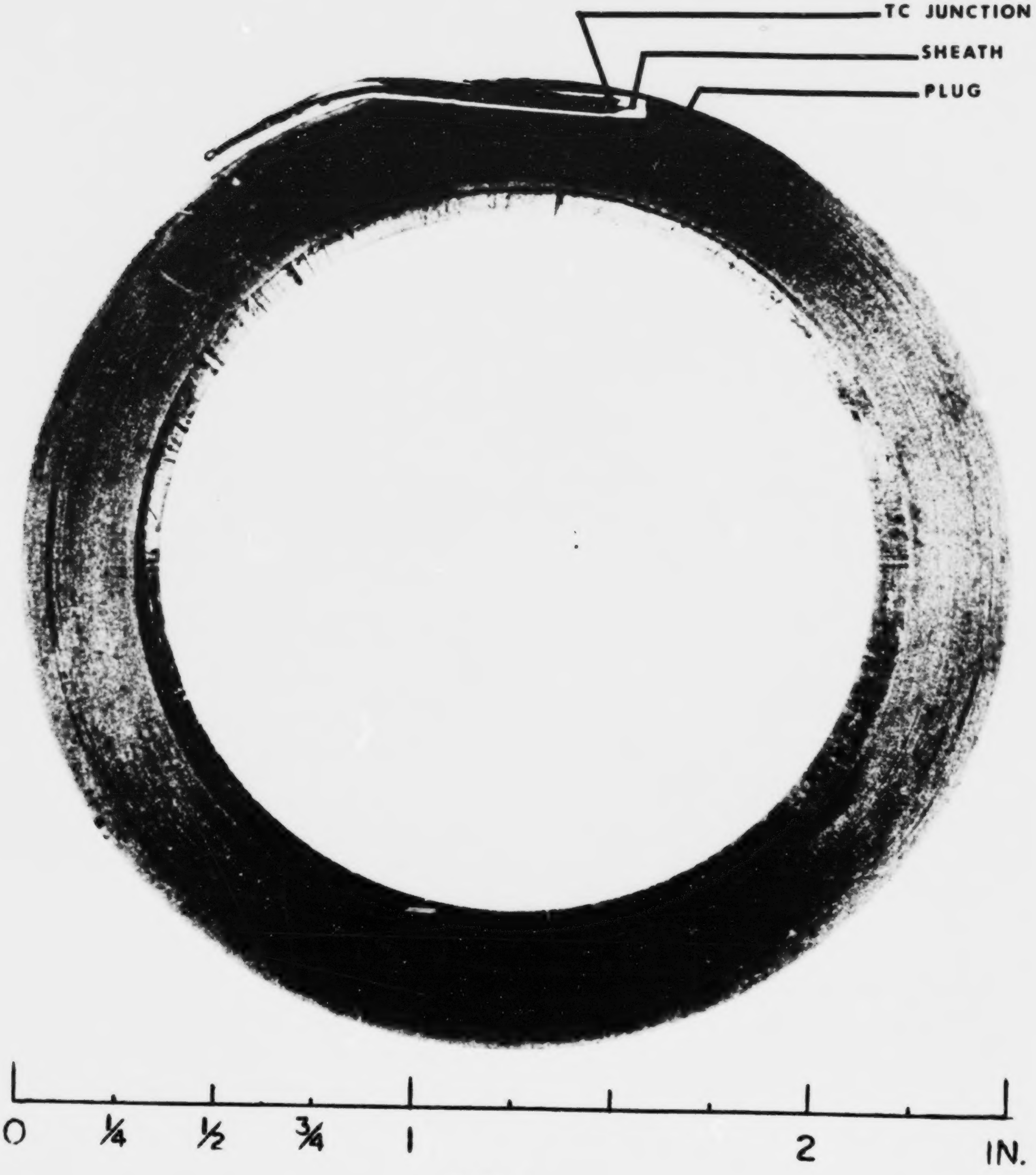
APPENDIX E–SHEET 2

CHORDAL DRILLED THERMOCOUPLE


DRILL .0625
P
.0625
Di
Do
DP
L

APPENDIX E—SHEET 3

THERMOCOUPLE INSTALLATION


TC JUNCTION
SHEATH
PLUG
0
¼
½
¾
1
2
IN.

SHEET 4
APPENDIX E

PROPERTIES OF HOT FINISHED and COLD DRAWN TUBES 1-1/4"OD

C - Low Carbon Steel
F - Ferritic Alloy Steel
S - Stainless Steel

H.S. Sq. ft./lin. ft = 0.3270

Minimum Tube Wall Thickness (Inch)	Avg. I.D. (Inch)	Hot Finish (ID)$^{4.97}$	Inside Area (Sq.Ft.)	Avg. I.D. (Inch)	Cold Drawn (ID)$^{4.97}$	Inside Area (Sq.Ft.)
.110	.9915	.9584	.005361	1.008	1.0403	.005541
.120	.9680	.8500	.005110	.9860	.9324	.005300
.125	.9562	.8006	.004987	.9750	.8817	.005184
.134 FS	.9351	.7164	.004769	.9552	.7962	.004976
.135 C	.9327	.7075	.004745	.9530	.7872	.004953
.148 FS	.9022	.5995	.004439	.9244	.6765	.004660
.150 C	.8975	.5842	.004393	.9200	.6607	.004616
.165 CFS	.8655	.4879	.004086	.8870	.5510	.004291
.180 CFS	.8306	.3975	.003762	.8540	.4563	.003977
.200 C	.7940	.3177	.003438	.8100	.3508	.003578
.203 FS	.7871	.3177	.003379	.8034	.3369	.003520
.220 CFS	.7484	.2368	.003054	.7660	.2658	.003200
.238 FS	.7073	.1789	.002729	.7264	.2041	.002877
*.240 C	.7028	.1732	.002693	.7220	.1981	.002843
.250 S				.7000	.1698	.002670
.260 FS				.6780	.1449	.002507
.280 C				.6340	.1038	.002192
.281 FS				.6318	.1020	.002177
.300 CFS				.5900	.07263	.001898
.313 S				.5614	.05673	.001718
.320 CFS				.5460	.04941	.001625

*Ferritic tubing to be hot finished except gages exceeding .240 which will be cold drawn.

All Stainless Steel Tubing to be Cold Drawn.

PROPERTIES OF HOT FINISHED and COLD DRAWN TUBES 1-1/2"OD

C - Low Carbon Steel
F - Ferritic Alloy Steel
S - Stainless Steel

H.S. Sq. ft./lin. ft = 0.3930

		Hot Finish			Cold Drawn	
Minimum Tube Wall Thickness (Inch)	Avg. I.D. (Inch)	$(ID)^{4.97}$	Inside Area (Sq.Ft.)	Avg. I.D. (Inch)	$(ID)^{4.97}$	Inside Area (Sq.Ft.)
.110	1.241	2.930	.008406	1.258	3.129	.008631
.125	1.206	2.539	.007936	1.225	2.741	.008184
.134 FS	1.185	2.325	.007660	1.2052	2.528	.007922
.135 C	1.182	2.302	.007629	1.203	2.505	.007893
.148 FS	1.152	2.022	.007240	1.174	2.223	.007522
.150 C	1.147	1.981	.007181	1.170	2.182	.007466
.165 CFS	1.115	1.721	.006787	1.137	1.892	.007050
.180 CFS	1.080	1.469	.006368	1.104	1.635	.006647
.188 S	1.071	1.408	.006260	1.086	1.509	.006437
.200 C	1.044	1.238	.005944	1.060	1.335	.006128
.203 FS	1.037	1.198	.005867	1.053	1.295	.006052
.220 CFS	.9984	.9920	.005436	1.016	1.082	.005630
.238 FS	.9573	.8052	.004998	.9764	.8880	.005199
.240 C	.9528	.7863	.004951	.9720	.8683	.005152
*.250 S	.9300	.6965	.004720	.9500	.7745	.004920
.260 CFS	.9072	.6162	.004488	.9280	.6897	.004697
.280 C				.8840	.5418	.004262
.281 FS				.8818	.5351	.004240
.300 CFS				.8400	.4204	.003848
.313 S				.8114	.3539	.003590
.320 CFS				.7960	.3217	.003455
.340 CFS				.7520	.2425	.003084
.360 CFS				.7080	.1797	.002733
.375 FS				.6750	.1417	.002485
.380 C				.6640	.1306	.002404
.400 CFS				.6200	.09293	.002096

*All Ferritic tubing to be hot finished except gages exceeding .250 will be cold drawn.

All Stainless Steel tubing will be Cold Drawn.

PROPERTIES OF HOT FINISHED and COLD DRAWN TUBES 1-3/4"OD

C - Low Carbon Steel
F - Ferritic Alloy Steel
S - Stainless Steel

H.S. Sq. ft./lin. ft = 0.458

Minimum Tube Wall Thickness (Inch)		Hot Finish			Cold Drawn	
	Avg. I.D. (Inch)	$(ID)^{4.97}$	Inside Area (Sq.Ft.)	Avg. I.D. (Inch)	$(ID)^{4.97}$	Inside Area (Sq.Ft.)
.110	1.491	7.293	.01213	1.505	7.647	.01236
.125	1.456	6.475	.01156	1.472	6.842	.01182
.134 FS	1.435	6.021	.01123	1.452	6.393	.01150
.135 C	1.432	5.972	.01119	1.450	6.345	.01147
.148 FS	1.402	5.365	.01072	1.421	5.741	.01102
.150 C	1.397	5.277	.01065	1.417	5.653	.01095
.165 CFS	1.365	4.704	.01017	1.383	5.023	.01044
.180 CFS	1.330	4.135	.009656	1.350	4.450	.009946
.188 S	1.321	3.994	.009522	1.332	4.166	.009686
.200 C	1.294	3.600	.009132	1.306	3.769	.009302
.203 FS	1.287	3.506	.009036	1.299	3.674	.009208
.220 CFS	1.248	3.012	.008500	1.261	3.173	.008681
.238 FS	1.207	2.551	.007950	1.221	2.704	.008139
.240 C	1.202	2.503	.007890	1.217	2.656	.008080
.250 S	1.180	2.276	.007600	1.196	2.438	.007800
.260 CFS	1.157	2.066	.007303	1.172	2.203	.007501
.280 C	1.111	1.691	.006739	1.128	1.822	.006944
.281 FS	1.109	1.674	.006711	1.126	1.805	.006917
.300 CFS				1.084	1.493	.006408
.313 S				1.055	1.305	.006072
.320 CFS				1.039	1.212	.005894
.340 CFS				.995	.976	.005401
.360 CFS				.950	.778	.004930
				.917	.651	.004591
.380 C				.906	.613	.004480
.400 CFS				.862	.478	.004052
.420 CS				.817	.367	.003645
.438 FS				.777	.286	.003298
.440 C				.773	.278	.003260

Ferritic tubing to be Hot finished except gages exceeding .281 which will be cold drawn.

All Stainless Steel Tubing to be Cold Drawn.

PROPERTIES OF HOT FINISHED and COLD DRAWN TUBES 2" OD

C - Low Carbon Steel
F - Ferritic Alloy Steel
S - Stainless Steel

H.S. Sq. ft./lin. ft = 0.5230

Minimum Tube Wall Thickness (Inch)	Avg. I.D. (Inch)	Hot Finish	Inside Area (Sq.Ft.)	Avg. I.D. (Inch)	Cold Drawn	Inside Area (Sq.Ft.)
		$(ID)^{4.97}$			$(ID)^{4.97}$	
.110	1.741	15.75	.01654	1.755	16.40	.01681
.125	1.706	14.23	.01587	1.722	14.91	.01618
.134 FS	1.685	13.37	.01548	1.702	14.07	.01580
.135 C	1.682	13.28	.01544	1.700	13.98	.01576
.148 FS	1.652	12.12	.01488	1.671	12.84	.01523
.150 C	1.647	11.95	.01480	1.667	12.67	.01515
.165 CFS	1.615	10.84	.01423	1.633	11.46	.01455
.180 CFS	1.580	9.730	.01362	1.600	10.35	.01396
.188 S	1.571	9.451	.01346	1.582	9.793	.01366
.200 C	1.544	8.661	.01300	1.556	9.000	.01320
.203 FS	1.537	8.472	.01288	1.549	8.811	.01309
.220 CFS	1.498	7.462	.01224	1.511	7.794	.01246
.238 FS	1.457	6.500	.01158	1.471	6.822	.01181
.240 C	1.452	6.399	.01151	1.467	6.721	.01174
.250 S	0.430	5.916	.01115	1.446	6.252	.01142
.260 CFS	1.407	5.461	.01080	1.422	5.769	.01104
.280 C	1.361	4.636	.01011	1.378	4.928	.[illegible]6
.281 FS	1.359	4.598	.01007	1.376	4.888	.01032
.300 CFS	1.316	3.914	.009445	1.334	4.138	.009705
.313 S	1.286	3.495	.009025	1.305	3.756	.009290
.320 CFS	1.270	3.285	.008802	1.289	3.539	.009070
.340 CFS	1.224	2.739	.008181	1.245	2.973	.008456
*.360 CFS	1.179	2.268	.007584	1.200	2.482	.007864
*.375 FS	1.145	1.960	.007150	1.167	2.159	.007434
.380 C	1.133	1.864	.007008	1.156	2.058	.007293
*.400 CFS				1.112	1.694	.006744
.420 CS				1.067	1.384	.006216
.438 FS				1.027	1.145	.005759
.440 C				1.023	1.120	.005710
.460 C				.9788	.8989	.005225
.500 FS				.8900	.5603	.004320
.531				.8211	.3756	.003677
.563				.7501	.2395	.003069
.594				.6813	.1485	.002531
.625				.6125	.08748	.002046

*Ferritic tubing to be hot finished except the following gages and heavier will be cold drawn:

C.S. - .360 T-11 - .400
C.M. - .360 T-9 - .360
T-22 - .375

All Stainless Steel Tubing to be Cold Drawn

PROPERTIES OF HOT FINISHED and COLD DRAWN TUBES 2-1/2"OD

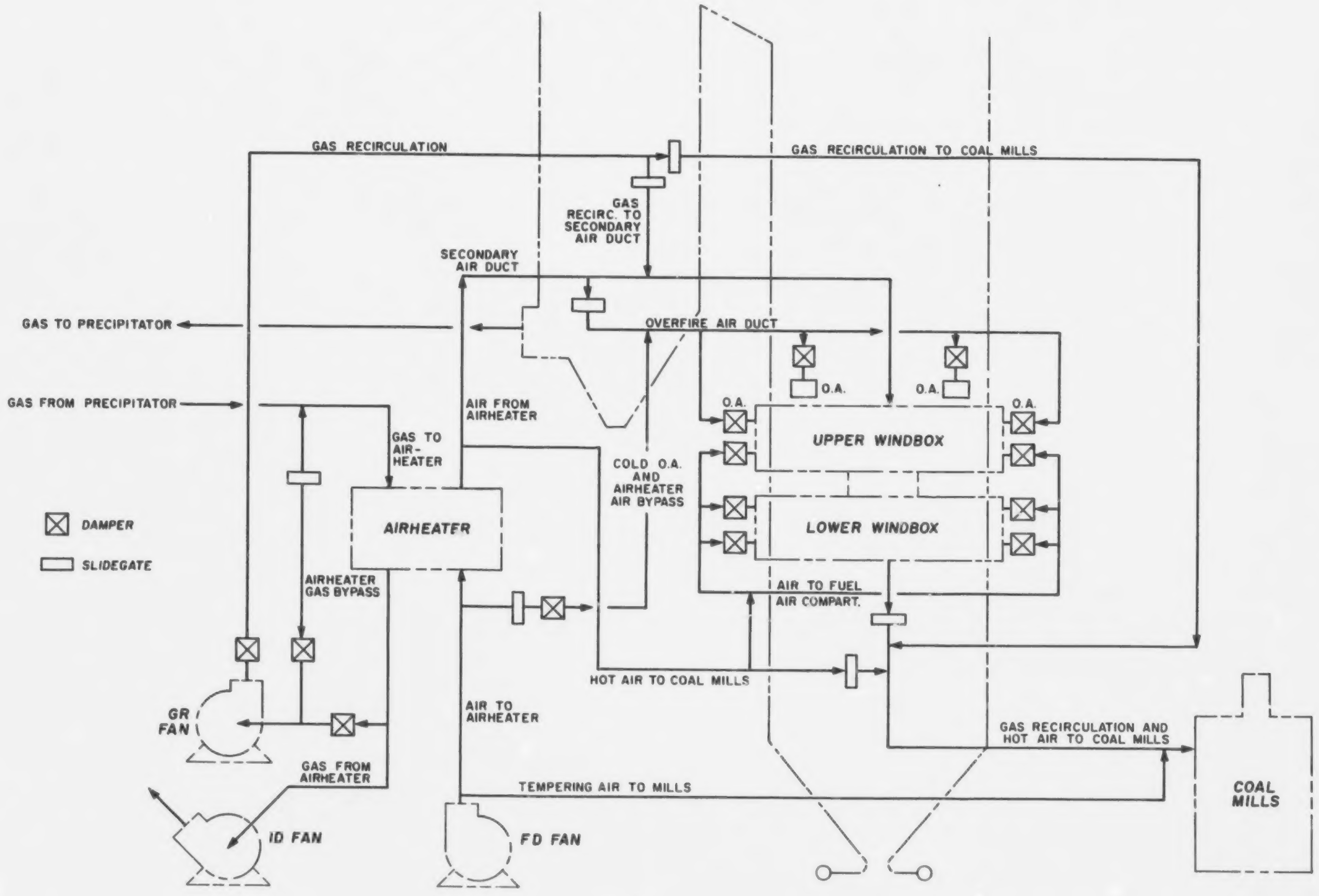
C - Low Carbon Steel
F - Ferritic Alloy Steel
S - Stainless Steel

H.S. Sq. ft./lin. ft = 0.655

Minimum Tube Wall Thickness (Inch)	Avg. I.D. (Inch)	Hot Finish (ID)$^{4.97}$	Inside Area (Sq.Ft.)	Avg. I.D. (Inch)	Cold Drawn (ID)$^{4.97}$	Inside Area (Sq.Ft.)
.110	2.241	55.23	.02740	2.255	57.00	.02775
.125	2.206	51.04	.02654	2.222	52.94	.02694
.134 FS	2.185	48.66	.02604	2.202	50.61	.02645
.135 C	2.182	48.40	.02598	2.200	50.36	.02640
.148 FS	2.152	45.12	.02526	2.171	47.16	.02571
.150 C	2.147	44.63	.02515	2.167	46.68	.02561
.165 CFS	2.115	41.43	.02441	2.133	43.23	.02483
.180 CFS	2.080	38.14	.02361	2.100	39.97	.02406
.188 S	2.071	37.30	.02340	2.082	38.32	.02365
.200 C	2.044	34.92	.02278	2.056	35.95	.02305
.203 FS	2.037	34.34	.02263	2.049	35.37	.02290
.220 CFS	1.998	31.21	.02178	2.011	32.25	.02207
.238 FS	1.957	28.15	.02089	1.971	29.19	.02120
.240 C	1.952	27.83	.02079	1.967	28.86	.02110
.250 S	1.930	26.35	.02030	1.946	27.40	.02070
.260 CFS	1.907	24.74	.01983	1.922	25.77	.02016
.280 C	1.861	21.94	.01890	1.878	22.94	.01924
.281 FS	1.859	21.81	.01885	1.876	22.81	.01919
.300 CFS	1.816	19.40	.01798	1.834	20.37	.01834
.313 S	1.786	17.87	.01740	1.805	18.83	.01777
.320 CFS	1.770	17.09	.01709	1.789	18.03	.01746
.340 CFS	1.724	15.01	.01622	1.745	15.92	.01661
.360 CFS	1.679	13.14	.01537	1.700	14.00	.01577
.375 FS	1.645	11.86	.01475	1.667	12.69	.01516
.380 C	1.633	11.46	.01455	1.656	12.28	.01496
.400 CFS	1.588	9.959	.01375	1.612	10.73	.01417
.420 CS	1.542	8.616	.01297	1.567	9.339	.01340
.428 FS	Ferritic Tubing to be Hot Finished except gages exceeding .420 which will be cold drawn.			1.527	8.214	.01272
.440 C				1.523	8.096	.01265
.460 C				1.478	6.989	.01192
.500 FS				1.390	5.137	.01053

All Stainless Steel tubing to be Cold Drawn.

SCHEMATIC-OVERFIRE AIR & GAS RECIRCULATION SYSTEMS
ALABAMA POWER CO. BARRY STA. No. 1


GAS RECIRCULATION
GAS RECIRCULATION TO COAL MILLS
GAS RECIRC. TO SECONDARY AIR DUCT
SECONDARY AIR DUCT
GAS TO PRECIPITATOR
OVERFIRE AIR DUCT
GAS FROM PRECIPITATOR
AIR FROM AIRHEATER
GAS TO AIR-HEATER
O.A.
O.A.
O.A.
O.A.
UPPER WINDBOX
COLD O.A. AND AIRHEATER AIR BYPASS
LOWER WINDBOX
DAMPER
SLIDEGATE
AIRHEATER
AIRHEATER GAS BYPASS
AIR TO FUEL AIR COMPART.
HOT AIR TO COAL MILLS
GR FAN
AIR TO AIRHEATER
GAS RECIRCULATION AND HOT AIR TO COAL MILLS
GAS FROM AIRHEATER
TEMPERING AIR TO MILLS
COAL MILLS
ID FAN
FD FAN

TEST PROGRAM FOR THE EVALUATION OF BIASED FIRING, OVERFIRE AIR, AND EXISTING PROCESS VARIABLES

CONTRACT NO. 68-02-0264
(CE CONTRACT 6472)

PILOT FIELD TEST PROGRAM TO STUDY METHODS FOR REDUCTION OF NO_X FORMATION IN TANGENTIALLY COAL FIRED STEAM GENERATING UNITS

PREPARED FOR
THE ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK,
NORTH CAROLINA 27711

APRIL 19, 1973
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INTRODUCTION

The emphasis on improved quality of our environment as a major national goal is providing additional challenges in the design and operation of fossil-fueled utility steam generators. Until recently, R&D activity involved in steam generator design and operation has traditionally been directed toward reducing equipment and operating costs while improving reliability and availability of equipment.

Advances in combustion and control technology have minimized smoke, CO, hydrocarbon and solid combustible emissions. The application of electrostatic precipitators has greatly reduced particulate emissions and more recently, wet scrubber systems for removal of sulfur oxides, as well as particulate matter, provide an approach to the control of most pollutants with the exception of NO_x which is not readily removed in a wet scrubbing system.

Modification of the combustion process has been found to be effective in reducing NO_x formation in oil and gas fired utility steam generators. Recent work with coal fired steam generators has demonstrated that overfire air simulation with tangential firing has been effective in reducing NO_x by as much as 50% of uncontrolled values. The major problem to be evaluated is the applicability of overfire air as viable means for control of NO_x emissions with coal firing.

For this reason, C-E proposed that a program be undertaken for the evaluation of overfire air as a feasible method for reduction of NO_x emissions from coal firing utility boilers. A program of this nature can be best conducted on a commercial size pilot plant unit which will provide the basis for evaluating potential operating and control problems and establishing the optimum methods for NO_x reduction. This approach is particularly valid for tangential firing where there is considerable interaction between the various fuel and air streams.

PROGRAM OBJECTIVES

The objective of this program is to investigate the effectiveness of employing overfire air as a method of reducing NO_x emission levels from tangentially coal fired steam generators.

Specifically, the factors to be considered in realizing this objective are as follows:

1. The program will be conducted on the 125 MW Alabama Power Company, Barry Station #1. This unit is large enough to provide furnace characteristics representative of large utility designs but of a size which will minimize modification costs and permit a versatile test program.

   In addition, Alabama Power Company has expressed a willingness to cooperate in this program and the Barry Station is located favorably for receiving various coals and has the facilities for handling these coals.

2. The overfire air system will be designed to avoid interference with the installation of further control systems, such as gas recirculation to the secondary air duct or coal pulverizers or air preheat variation, should the results of this study indicate the necessity for further NO_x emission control effort with coal firing.

3. To properly assess the effect of combustion modifications on unit performance and emission level, baseline tests will be conducted prior to modification to evaluate operation with normal and biased firing techniques. This test series will include investigation of the effects of biased firing on flame stability, thermal performance and long term corrosion.

4. The effect of NO_x control methods on other gas constituents will be evaluated during all test phases. The following constituents will be measured. NO_x, SO_x, CO, HC, O_2 and particulate samples for unburned combustible analysis. In addition, selected gas samples will be obtained for PNA analysis by EPA.

5. The overfire air test program will evaluate the various optimized modes of overfire air operation with respect to unit transient operation, long term corrosion effects, steam generator performance and applicability to a range of coal fuels. One additional coal will be evaluated with consideration given to a second additional coal based on program results and availability of this coal.

6. Based on the result of the test program, conclusions and recommendations will be made pertaining to the application of the technology developed during the program, to new and existing boiler designs. In addition, properly founded and projected recommendations for further NO_x control effort in coal firing will be developed.

PROGRAM OUTLINE

Task I - Overfire Air System Design and Program Scheduling

A. Drawings

The design, detailed fabrication and erection drawings for installation of the overfire air system will be completed. Specifically the overfire air system will be designed to:

1. Introduce a maximum of 20% of the total combustion air above the fuel admission nozzles.
2. Provide for introducing the overfire air through the top two compartments of the unit windbox as well as two additional compartments in each furnace corner located approximately eight feet above the fuel admission zone.
3. Control the vertical angle and velocity of air admission.
4. The design shall make full consideration for future addition of alternate NO_x control methods such as air preheat control and gas recirculation to the secondary air compartments and coal pulverizers.

B. Scheduling

An updated schedule for Tasks II through VI will be prepared relative to date of contract approval and unit outage dates. This schedule will define major milestones to be accomplished in completing these tasks.

Task II - System Fabrication

A. Upon approval of the modification drawings defined under Task I by EPA, the necessary equipment will be purchased, and pre-fabrication of the overfire air ports, ductwork, auxiliary equipment etc. necessary for modification of the unit will be completed.

B. Instrumentation required for the baseline and optimization test phases of the program will be fabricated, calibrated as required, and prepared for shipment to the test unit site. This effort will include such items as fabrication of corrosion probes, probe control systems, and gas temperature and sampling probes, calibration of thermocouples, analyzers and transducers and packaging of equipment for shipment.

Task III - Instrumentation Installation

Instrumentation necessary to conduct the baseline and biased firing test programs will be installed and calibrated. This instrumentation will consist of the following:

Measurement	Instrument
Flue Gas Constituents	
NO_x	Chemiluminescence Analy.
SO_2	Wet Chemistry
CO & Hydrocarbons	Infrared Analy. and Flame Ionization Analy.
Carbon Loss	Dust Collector
Oxygen	Paramagnetic Analyzer
Fuel Analysis	ASTM Procedures
Ash Analysis	ASTM Procedures
Flow Rates	
Steam & Water	
Feedwater Flow	Flow Orifice
RH & SH Desuperheat Spray Flow	Heat Balance (°F & PSIG) Around Desuperheater
RH Flow	Heat Balance Around Superheat Extractions and Est. Turbine Gland Seal Losses
Coal Flow	Coal Scale Readings
Air & Gas	
Total Air & Gas Wt.	Calculated
Overfire Air	Pitot Traverse
Air Heater Leakage	Paramagnetic O_2 Analyzer

Temperatures	
Steam & Water °F	
Unit Absorption Rates	Calibrated Stainless Steel Sheathed C_R-C Well & Button TC's
WW Absorption[1].	Calibrated Stainless Steel Sheathed C_R-C Chordal WW TC's
Air & Gas °F	C_R-C TC's Water Cooled Probes PL/PL-10% R_h TC's
Pressures	
Steam & Water-PSIG	
Unit Absorption Rates	Pressure Gauges and/or Transducers
Unit Draft Loss	Water Manometers
Temperature and Pressure Logging °F & PSI	C-E Data Logger Capacity: 400 temperatures, 50 pressures

Task IV - Baseline Tests - Load and Excess Air Variation

A program will be conducted to establish the effect of unit load wall slagging and excess air variation on baseline emission levels, thermal performance, corrosion rates and operating ranges. A baseline corrosion test of four week duration will also be conducted at maximum load conditions.

1.) To be installed during Task VI

There will be 14 tests run for the combination of conditions shown in Table 1.

Table 1

		E-1	E-2	E-3
D-1	L-1	5	6	7
	L-2		4	
	L-3	1	2	3
D-2	L-1	8	9	10
	L-2			
	L-3			
D-3	L-1	13		14
	L-2			
	L-3	11		12

Test Conditions

Percent Excess Air-Max. Unit Load

Normal Excess Air	E-1
Minimum Excess Air	E-2
Maximum Excess Air	E-3

Furnace Wall Deposits

Clean	D-1
Moderate	D-2
Heavy	D-3

Percent Load

Max. Load	L-1
3/4 Max. Load	L-2
1/2 Max. Load	L-3

At the completion of test 14, the unit will be operated with normal excess air and unit loading for a 4 week corrosion test period. During the 4 week period maximum load will be carried whenever possible.

Task V - Baseline Tests - Bias Firing

A test program will be conducted to establish the effect on emission levels of operation with various fuel elevations out of service. Specifically, this program will evaluate:

1. Maximum emissions control throughout the normal load range.
2. Maximum emissions control at full load only.
3. Control of emissions to meet and maintain emissions standards throughout the normal load range.

A corrosion test of four week duration will also be conducted at the optimum biased firing condition. During the 4 week period, unit loading will be varied similar to the loading schedule followed during the baseline corrosion test program.

There will be 10 tests run at the conditions identified in Table 2.

Table 2

	L-1	L-2	L-3
B-1	6	7	8
B-2	5		9
B-3	4		10
B-4	3	2	1

Test Conditions

Firing Elevation Out of Service - Dampers Open

Top Elevation	B-1
Top Center Elevation	B-2
Bottom Center Elevation	B-3
Bottom Elevation	B-4

Percent Load

Max. Load	L-1
3/4 Max. Load	L-2
1/2 Max. Load	L-3

At the completion of test 10, the unit will be operated at optimized conditions and normal unit loading for a 4 week corrosion test period. Unit loading will be varied during the test period on a schedule similar to that followed during the baseline corrosion test period.

Task VI - Equipment Delivery and Installation

The equipment necessary for completing the overfire air modification will be delivered to the test site and installed on the test unit in accordance with the approved erection drawings. Delivery and installation of equipment will be coordinated with scheduled unit outages as defined by the updated schedule to be prepared under Task I.

Task VII - Final Test Preparation

During the unit modification outage the following final preparations will be made for conducting the overfire air optimization test program defined in Task VIII.

1. The waterwall thermocouples will be installed as defined in the detailed test program.
2. Thermocouples will be installed on the fuel, air and overfire air nozzles to determine the effect of overfire air optimization on nozzle temperatures and wastage rates.

3. All instrumentation and readouts will be checked for proper installation and operability.
4. The test program will be updated and reviewed with Alabama Power Company and the EPA Project Officer for final approval.
5. The test unit will be inspected to assure proper operating of all dampers, tilting mechanisms and their operators and to establish acceptable operating condition of fuel nozzles, air preheaters, pulverizers and soot blowing systems.

Task VIII - Unit Optimization Program

The experimental program updated and approved in Task VII will be conducted in Task VIII and the data generated will be analyzed, correlated and compared to data generated during Task V. A comprehensive report will then be developed relating the effectiveness of each method of emission control with respect to unit thermal and operational performance.

The test program will investigate the effect of overfire air location and introduction rates at various unit loadings and operating conditions. Those methods which are found to be optimum from the standpoint of both effectiveness in reducing emission levels and unit operation will then be evaluated to determine their acceptability for long term operation and their applicability to alternate coal types.

A. Unit Load and Excess Air Variation

The object of this evaluation is to determine baseline operating characteristic of the modified unit and to compare these with the unmodified unit test results. There will be 14 tests run (1 thru 14) at the conditions identified in Table 3.

Table 3

		E-1	E-2	E-3
D-1	L-1	5	6	7
	L-2		4	
	L-3	1	2	3
D-2	L-1	8	9	10
	L-2			
	L-3			
D-3	L-1	13		14
	L-2			
	L-3	11		12

Test Conditions

Percent Excess Air	
Normal Excess Air	E-1
Minimum Excess Air	E-2
Maximum Excess Air	E-3
Furnace Wall Deposits	
Clean	D-1
Moderate	D-2
Heavy	D-3
Percent Load	
Max. Load	L-1
3/4 Max. Load	L-2
1/2 Max. Load	L-3

B. Overfire Air Location, Rate and Velocity - Full Load

The object of this evaluation is to determine:

1. The effect on the NO_x emission level of varying the velocity and height above tne fuel compartments at which the overfire air is admitted.

2. The effect on the NO_x emission level of varying the overfire air rate.
3. The maximum overfire air rate with respect to steam temperatures, flame stability and furnace wall deposits.

There will be 9 tests run (tests 15 thru 23) at the conditions identified in Table 4.

Table 4

	0-1	0-2	0-1 0-2	0-2	0-3 0-4	0-1 0-2	0-3 0-4
A-1	15						
A-2			19			23	
A-3	16	17	18	20	21	22	

Test Conditions

Overfire Air Admission Points

Eight Feet Above Fuel Compartments (high)	Top	0-1
	Bottom	0-2
Immediately Above Fuel Compartments (low)	Top	0-3
	Bottom	0-4

Overfire Air Rate and Temperature

No Overfire Air	A-1
1/2 Max. Overfire Air	A-2
Max. Overfire Air	A-3

C. Overfire Air Tilt Variation

Having established the optimum overfire air location, rate, velocity and temperature, this condition will be used to perform the tilt variation tests. In the event that more than one optimum combination is noted, the tilt variation test will be performed with each combination.

The object of this evaluation is to determine:

1. The effect of tilting overfire air compartment nozzles on the NO_x emission level.
2. If the overfire air compartment nozzles should tilt with the fuel nozzles or remain fixed.
3. The maximum allowable minus and plus tilt with respect to steam temperatures and furnace wall deposits.

There will be 6 tests run (tests 24 thru 29) at the conditions identified in Table 5.

Table 5

	P-1	P-2	P-3
F-1	24	27	
F-2	25		29
F-3	26	28	

Test Conditions

Overfire Air Compartment Tilt

Horizontal Tilt	P-1
Maximum Minus Tilt	P-2
Maximum Plus Tilt	P-3

Fuel Nozzle Tilt

Horizontal Tilt	F-1
Maximum Minus Tilt	F-2
Maximum Plus Tilt	F-3

D. Load Variation At Optimum Conditions

The object of this evaluation is to determine:

1. The effect on the NO_x emission level of operating at previously determined optimum conditions for NO_x reduction while varying load and the degree of furnace wall deposits.
2. The effect on unit operation while operating at said conditions.

There will be 6 tests run (tests 30 thru 35) at the conditions identified in Table 6.

Table 6

		L-1	L-2	L-3
OC-1	D-1	32	31	30
	D-3	33	34	35

Test Conditions

Percent Load	
Max. Load	L-1
3/4 Max. Load	L-2
1/2 Max. Load	L-3
Furnace Wall Deposits	
Clean	D-1
Heavy	D-3
Optimum Conditions	
Optimum Conditions	OC-1

E. Overfire Air Evaluation - Second Coal Type

The object of this part of the program is to evaluate the objectives of test sections A, B, C and D on an alternate coal fuel. These sections will therefore be repeated to whatever degree necessary to verify acceptable baseline and optimum operation with the alternate coal.

F. Effect of Long Term and Transient Operation

After the optimized modes of operation have been established for each coal, they will be evaluated with respect to their effects on long term and transient operation. Each test will be conducted for a 4 week period during which unit loading will be varied on a schedule similar to that followed during the baseline and biased firing corrosion test programs. Furnace corrosion probe studies will be conducted during each test period.

Task IX - Application Guidelines

Based on the results of this study a program will be prepared outlining the application of the technology developed to existing and new design tangentially coal fired utility boilers.

The program will encompass the following three sub-tasks.

Sub-Task 1

Guidelines will be prepared for the application of the developed technology to existing boilers. These guidelines will define necessary procedures for applying the technology, the effect on those emissions evaluated in the study and the effect on unit performance.

The equipment necessary for modification of existing and new unit designs will be defined and the costs of these modifications will be developed for 4 unit sizes between 125 and 1000 MW.

Sub-Task 2

The applicability of the modifications developed during this study will be determined for all existing tangentially fired units in the U.S. Those units for which the technology is deemed unapplicable will be identified and the reasons discussed.

Sub-Task 3

The incorporation of the modifications developed in this study into new unit designs will be evaluated with respect to degree of applicability and costs.

The effect of these methods on emission control will be evaluated as well as the cost effectiveness thereof, considering capital costs, operating costs and equipment life.

SECTION VI

ATTACHMENT III

ENGINEERING DRAWINGS

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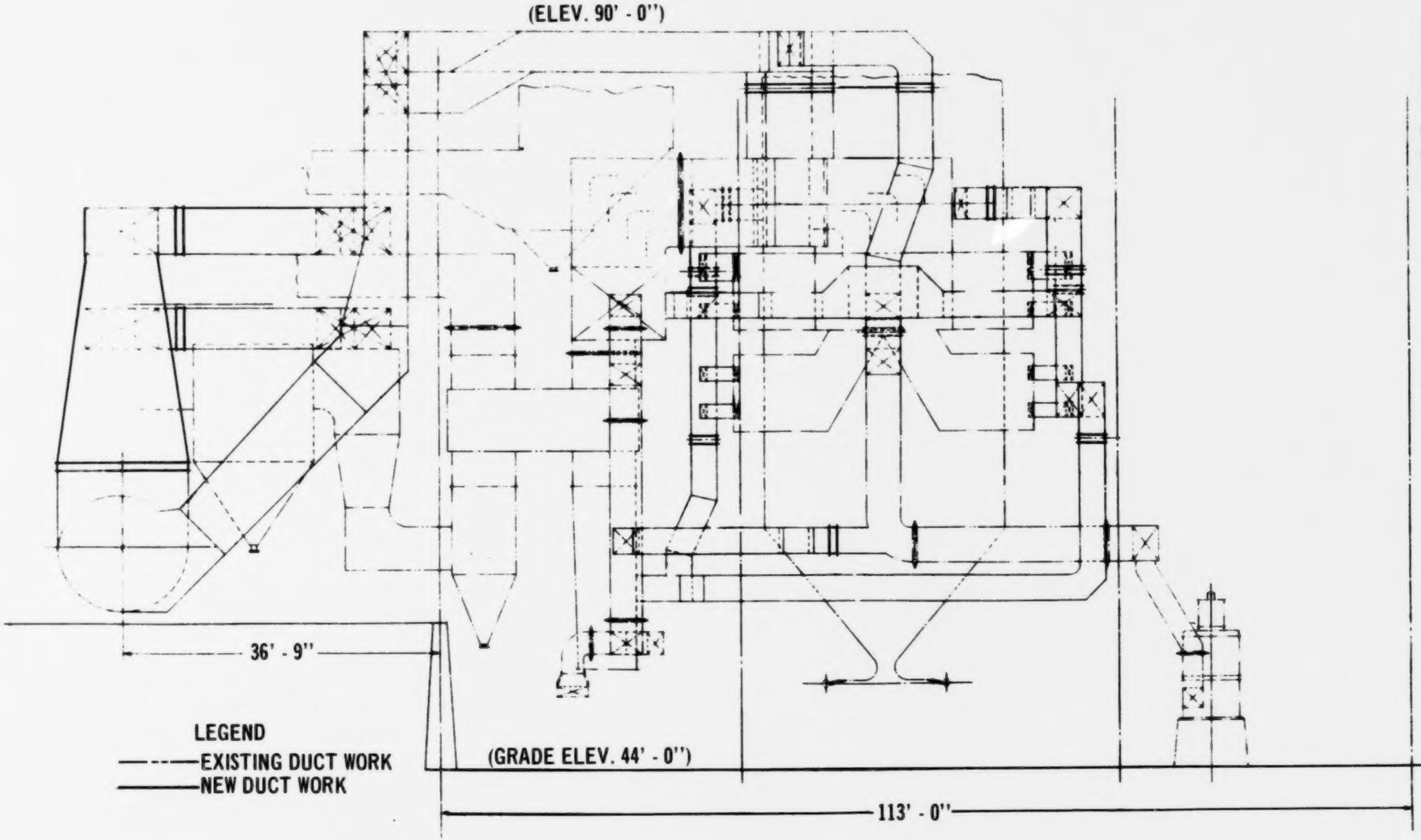
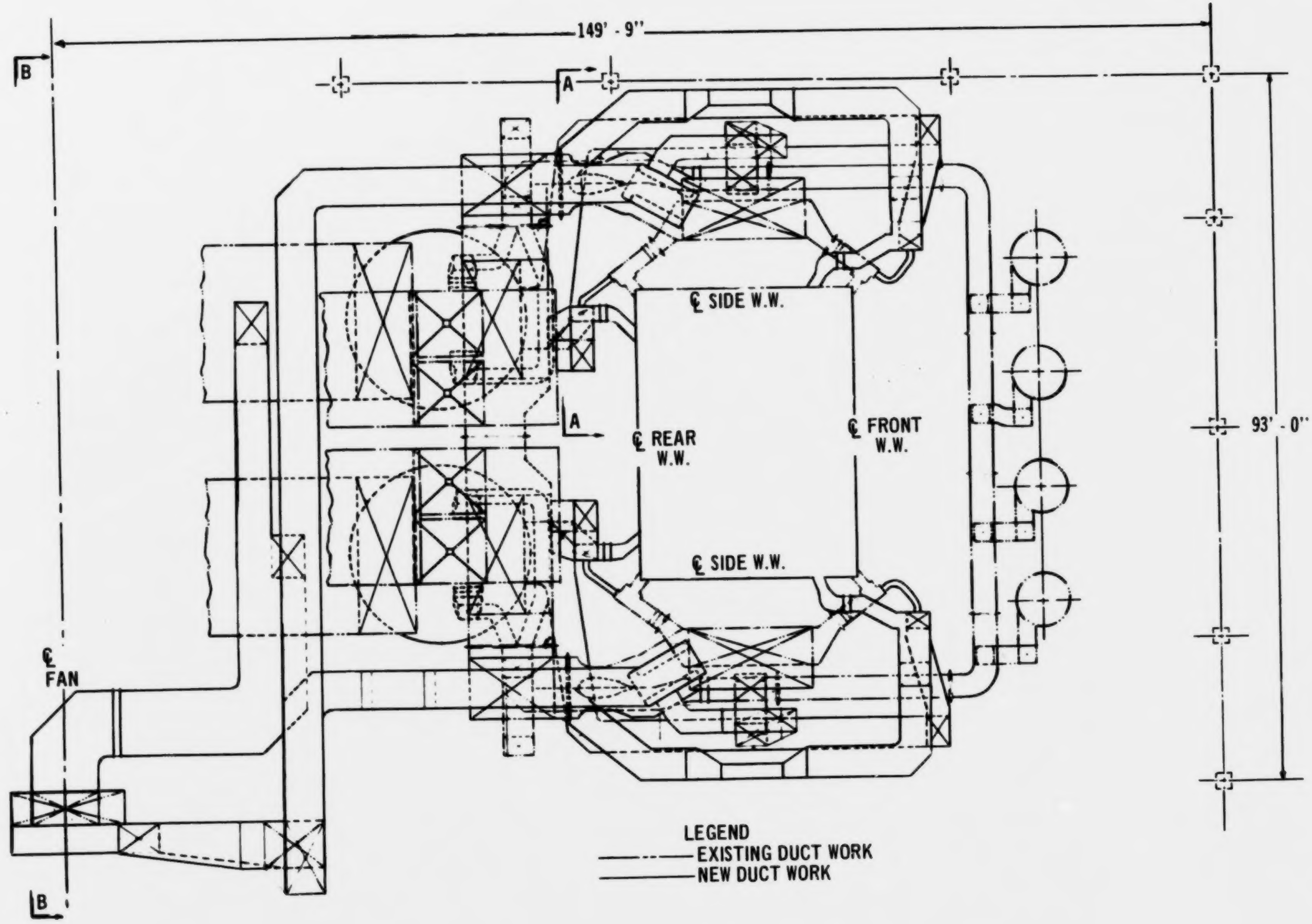
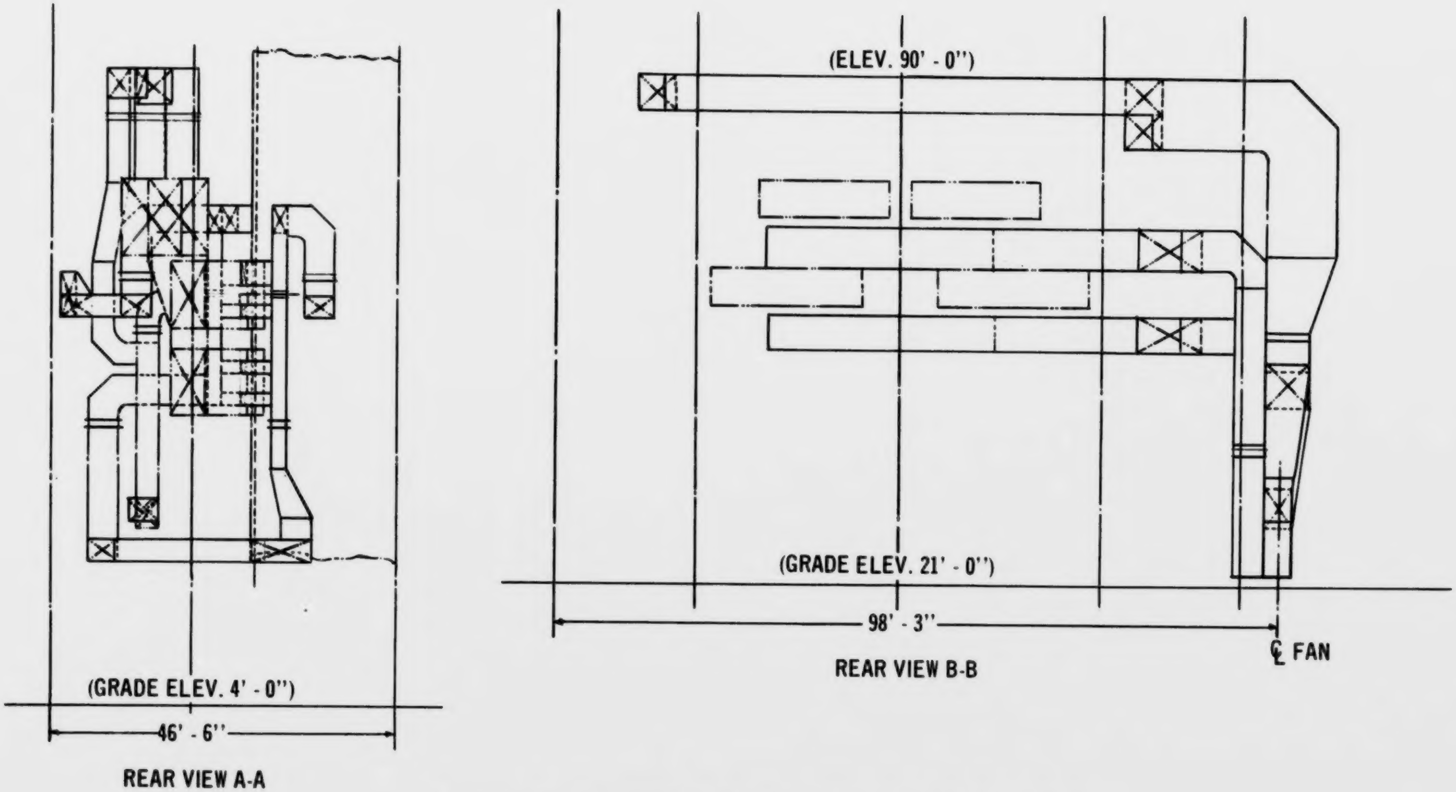

(ELEV. 90' - 0'')
(GRADE ELEV. 44' - 0'')
36' - 9''
113' - 0''
LEGEND
EXISTING DUCT WORK
NEW DUCT WORK

General arrangement of ducts -- side elevation.


149' - 9''
93' - 0''
B
A
A
B
℄ SIDE W.W.
℄ REAR W.W.
℄ FRONT W.W.
℄ SIDE W.W.
℄ FAN
LEGEND
EXISTING DUCT WORK
NEW DUCT WORK

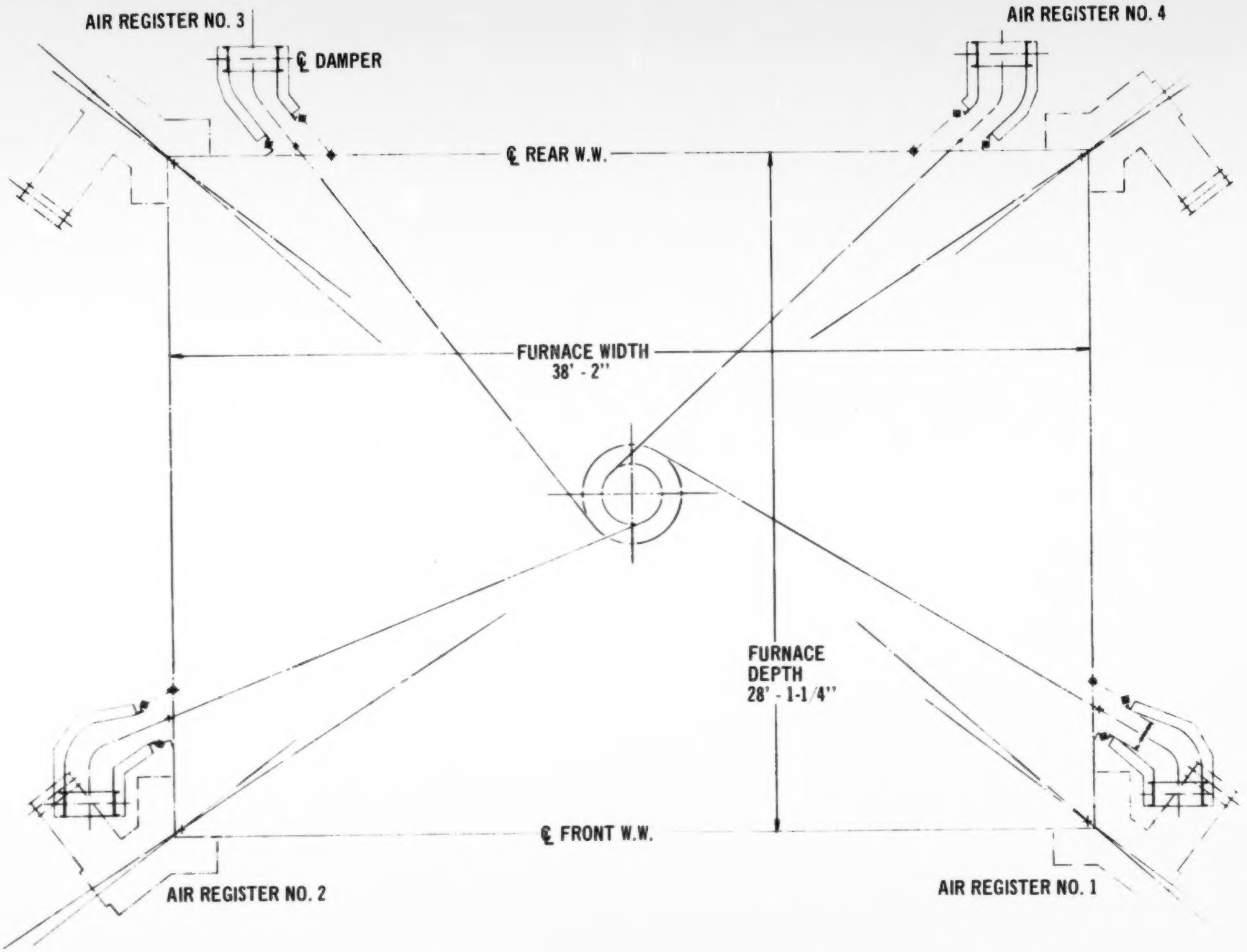
General arrangement of ducts -- plan view.


(ELEV. 90' - 0")
(GRADE ELEV. 21' - 0")
98' - 3"
℄ FAN
(GRADE ELEV. 4' - 0")
46' - 6"

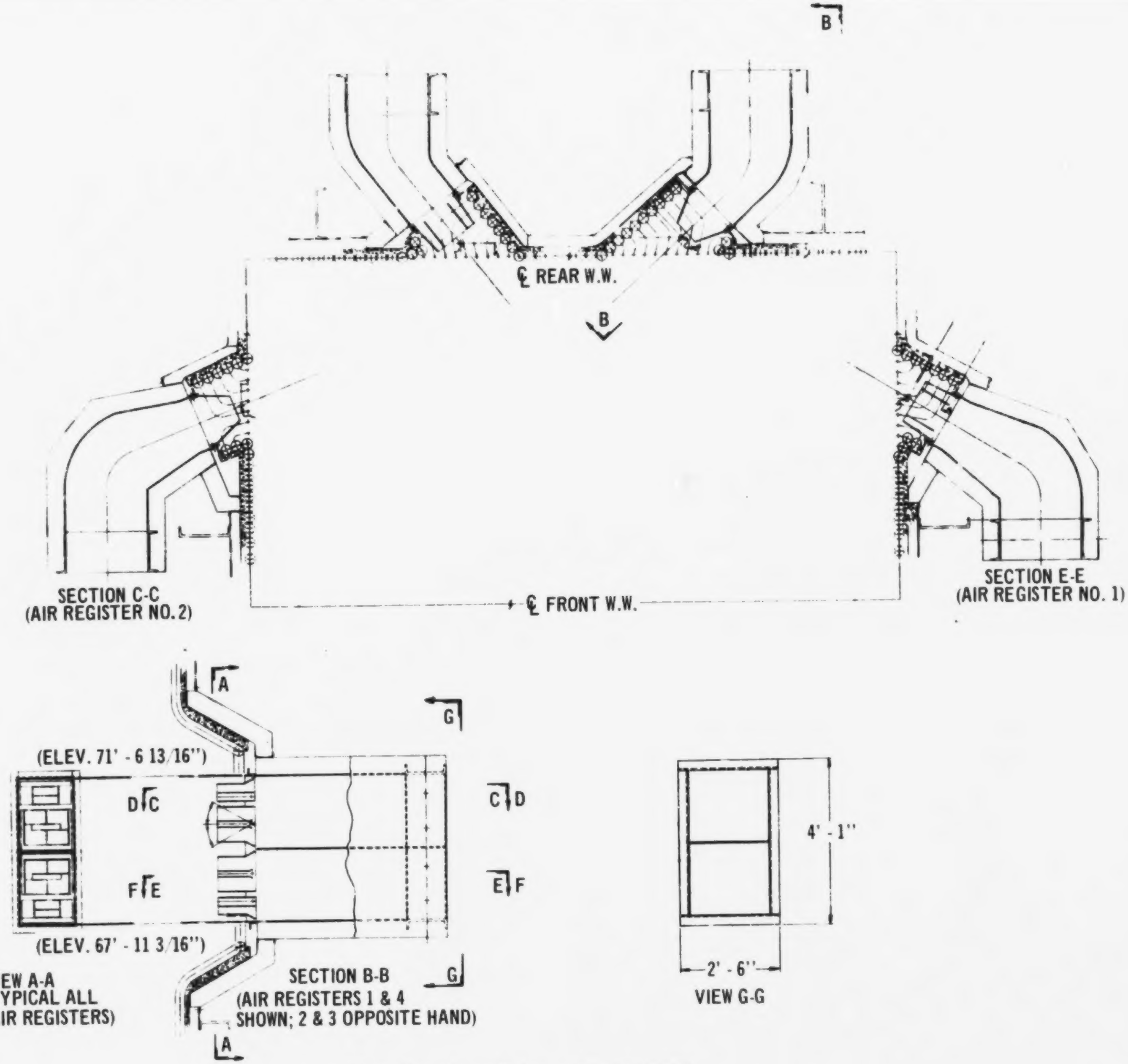
REAR VIEW A-A

REAR VIEW B-B

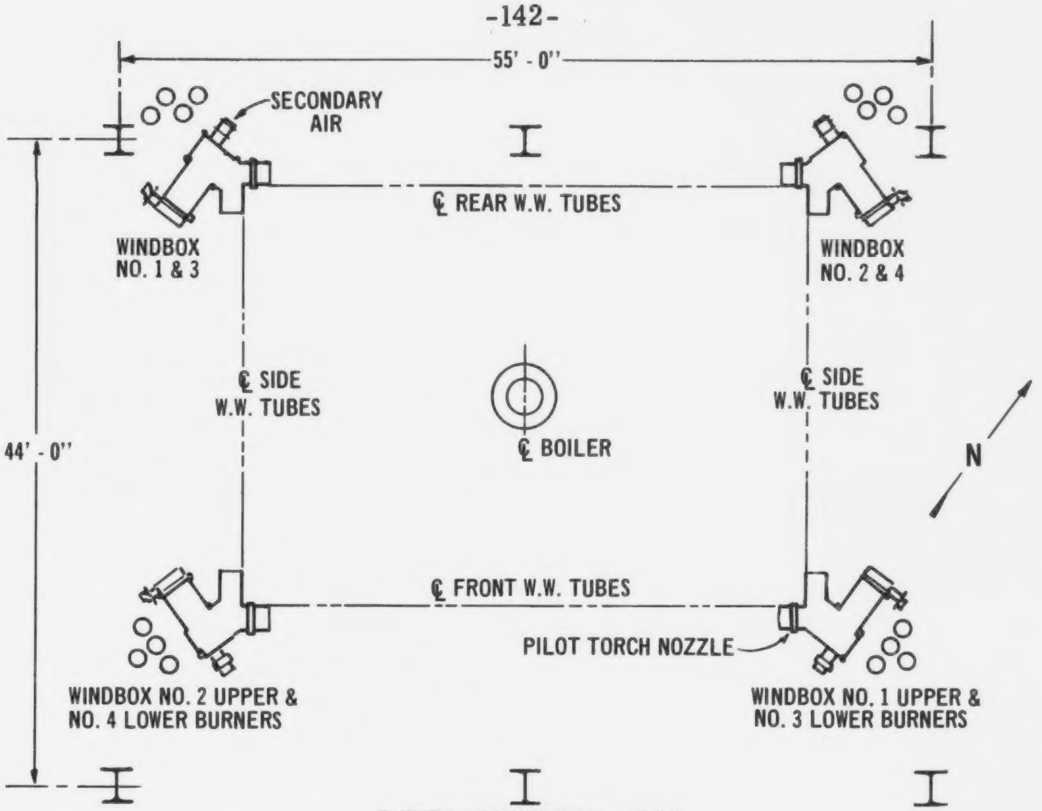
General arrangements of ducts -- rear views A-A and B-B.


AIR REGISTER NO. 3
℄ DAMPER
AIR REGISTER NO. 4
℄ REAR W.W.
FURNACE WIDTH
38' - 2"
FURNACE
DEPTH
28' - 1-1/4"
℄ FRONT W.W.
AIR REGISTER NO. 2
AIR REGISTER NO. 1

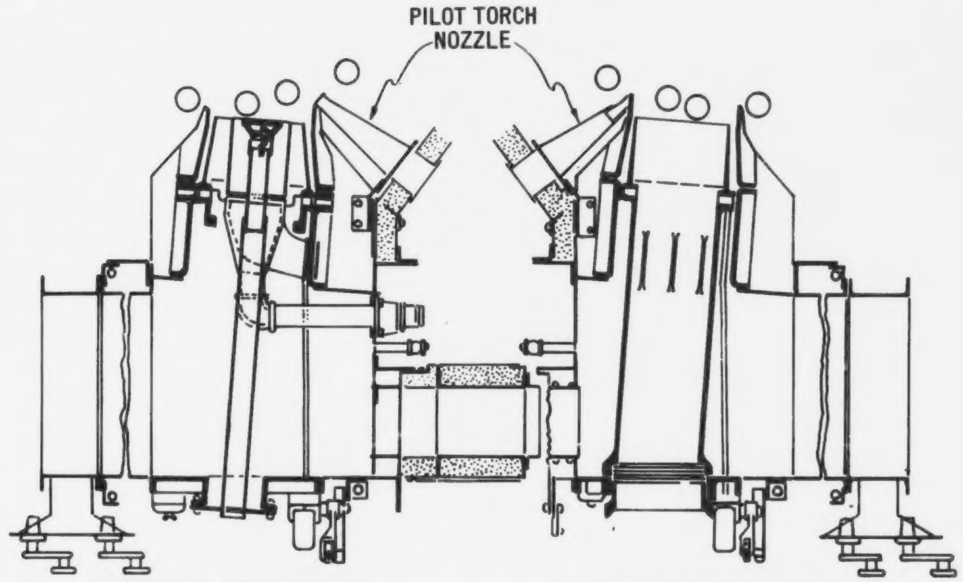
Overfire air register -- plan arrangement.


B
℄ REAR W.W.
B
SECTION C-C
(AIR REGISTER NO. 2)
℄ FRONT W.W.
SECTION E-E
(AIR REGISTER NO. 1)
A
G
(ELEV. 71' - 6 13/16")
D C
F E
C D
E F
(ELEV. 67' - 11 3/16")
VIEW A-A
(TYPICAL ALL
AIR REGISTERS)
SECTION B-B
(AIR REGISTERS 1 & 4
SHOWN; 2 & 3 OPPOSITE HAND)
G
A
4' - 1"
2' - 6"
VIEW G-G

Overfire air register -- arrangement.


55' - 0"
SECONDARY AIR
℄ REAR W.W. TUBES
WINDBOX NO. 1 & 3
WINDBOX NO. 2 & 4
℄ SIDE W.W. TUBES
℄ SIDE W.W. TUBES
44' - 0"
℄ BOILER
N
℄ FRONT W.W. TUBES
PILOT TORCH NOZZLE
WINDBOX NO. 2 UPPER & NO. 4 LOWER BURNERS
WINDBOX NO. 1 UPPER & NO. 3 LOWER BURNERS

BURNER ARRANGEMENT -- PLAN


PILOT TORCH NOZZLE

LH FRONT & RH REAR SECTION

RH FRONT & LH REAR SECTION

Tilting tangential - firing windbox -- arrangement.

SECTION VI

ATTACHMENT IV

COST ESTIMATES
FOR CONDUCTING PILOT FIELD TEST PROGRAMS

COST ESTIMATES FOR CONDUCTING PILOT FIELD TEST PROGRAMS

Cost estimates are presented using Optional Form 60 for the design fabrication, erection and testing of NO_X control systems for Barry No. 1 unit of Alabama Power Company. The scope of work and cost of each program are summarized below.

1. Evaluation of:
   Overfire Air System
   Gas Recirculation System
   Air Preheat System
   Water Injection System
   Existing Process Variables - - - - - $ 1,678,349

2. Same scope as item 1 performed in two stages.

   a.) Initial installation and evaluation of:
   Overfire Air System
   Air Preheat System
   Water Injection System
   Existing Process Variables ($753,070)

   b.) Later installation and evaluation of:
   Gas Recirculation System
   Combinations of above systems ($1,093,487)

   Total- - - - - $ 1,846,557

3. Evaluation of:
   Overfire Air System
   Existing Process Variables ($426,644)
   (including options for metric system and testing of third coal type) ($34,300)

   Total- - - - - $ 460,944

CONTRACT PRICING PROPOSAL

(RESEARCH AND DEVELOPMENT)

Office of Management and Budget
Approval No. 29-RO184

This form is for use when *(i)* submission of cost or pricing data (see FPR 1-3.807-3) is required and *(ii)* substitution for the Optional Form 59 is authorized by the contracting officer.

PAGE NO.

NO OF PAGES

NAME OF OFFEROR: Combustion Engineering, Inc.

HOME OFFICE ADDRESS:
1000 Prospect Hill Road
Windsor, Conn. 06095

SUPPLIES AND/OR SERVICES TO BE FURNISHED: Eqpmt, matl, and labor to modify existing boiler. Engrs and techs to investigate combust mod techniques for NOx contr by adding over-fire air and gas recirc systems.

DIVISION(S) AND LOCATION(S) WHERE WORK IS TO BE PERFORMED: Windsor, Conn., Chattanooga, Tenn., St. Louis, Mo. and Monongahela, Pa.

TOTAL AMOUNT OF PROPOSAL: $ 1,678,349.00

GOV'T SOLICITATION NO.: EPA-68-02-0264

DETAIL DESCRIPTION OF COST ELEMENTS

			EST COST ($)	TOTAL EST COST	REFERENCE
1. DIRECT MATERIAL *(Itemize on Exhibit A)*					
a. PURCHASED PARTS			181,856		
b. SUBCONTRACTED ITEMS			245,804		
c. OTHER—*(1)* RAW MATERIAL			80,633		
(2) YOUR STANDARD COMMERCIAL ITEMS					
(3) INTERDIVISIONAL TRANSFERS *(At other than cost)*					
TOTAL DIRECT MATERIAL				508,293	
2. MATERIAL OVERHEAD *(Rate %X$ base =)*					
3. DIRECT LABOR *(Specify)*	ESTIMATED HOURS	RATE/HOUR	EST COST ($)		
See Attachment 1					
TOTAL DIRECT LABOR				575,770	
4. LABOR OVERHEAD *(Specify Department or Cost Center)*	O.H. RATE	X BASE =	EST COST ($)		
See Attachment 1					
TOTAL LABOR OVERHEAD				335,137	
5. SPECIAL TESTING *(Including field work at Government installations)*			EST COST ($)		
TOTAL SPECIAL TESTING					
6. SPECIAL EQUIPMENT *(If direct charge) (Itemize on Exhibit A)*					
7. TRAVEL *(If direct charge) (Give details on attached Schedule)*			EST COST ($)		
a. TRANSPORTATION			31,403		
b. PER DIEM OR SUBSISTENCE			32,104		
TOTAL TRAVEL				63,507	
8. CONSULTANTS *(Identify—purpose—rate)*			EST COST ($)		
TOTAL CONSULTANTS				18,500	
9. OTHER DIRECT COSTS *(Itemize on Exhibit A)*					
10. *TOTAL DIRECT COST AND OVERHEAD*				1501,207	
11. GENERAL AND ADMINISTRATIVE EXPENSE *(Rate* 4 *% of cost element Nos.)*				60,048	
12. ROYALTIES					
13. *TOTAL ESTIMATED COST*				1561,255	
14. FEE OR PROFIT				117,094	
15. *TOTAL ESTIMATED COST AND FEE OR PROFIT*				1678,349	

OPTIONAL FORM 60
October 1971
General Services Administration
FPR 1-16.806
5060-101

This proposal is submitted for use in connection with and in response to *(Describe RFP, etc.)*

EPA Contract 68-02-0264

and reflects our best estimates as of this date, in accordance with the Instructions to Offerors and the Footnotes which follow.

TYPED NAME AND TITLE R. F. Swope Contract Administrator	SIGNATURE
NAME OF FIRM Combustion Engineering, Inc.	DATE OF SUBMISSION November 9, 1972

EXHIBIT A—SUPPORTING SCHEDULE *(Specify. If more space is needed, use reverse)*

COST EL NO.	ITEM DESCRIPTION *(See footnote 5)*		EST COST *($)*
1a	Insulation	32,855	
1a	Controls	29,329	
1a	Instrumentation	3,082	
1a	Gas Recirc Fan	73,592	
1a	Gas Recirc Fan Motor	42,998	181,856
1b	Setting, Insulation and Lagging Erection Equip.	37,000	
1b	Setting, Insulation and Lagging Erection Labor	133,454	
1b	Metal Erect., Equip. Rent., Tools, and Consumables	75,350	245,804
1c	Ductwork	36,046	
1c	Gates and Dampers	25,106	
1c	Boiler Mod. Tube Inserts	746	
1c	Structural Steel	18,735	80,633
7a	Freight 14,023, Car Rental 9,600, and Air Travel 7,780		31,403
9	Insurance	2,000	
9	Computer	13,000	
9	Misc Material	3,500	18,500

I. HAS ANY EXECUTIVE AGENCY OF THE UNITED STATES GOVERNMENT PERFORMED ANY REVIEW OF YOUR ACCOUNTS OR RECORDS IN CONNECTION WITH ANY OTHER GOVERNMENT PRIME CONTRACT OR SUBCONTRACT WITHIN THE PAST TWELVE MONTHS?

☒ YES ☐ NO *(If yes, identify below.)*

NAME AND ADDRESS OF REVIEWING OFFICE AND INDIVIDUAL AEC, Chicago Operations Office	TELEPHONE NUMBER/EXTENSION

II. WILL YOU REQUIRE THE USE OF ANY GOVERNMENT PROPERTY IN THE PERFORMANCE OF THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify on reverse or separate page)*

III. DO YOU REQUIRE GOVERNMENT CONTRACT FINANCING TO PERFORM THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify.):* ☐ ADVANCE PAYMENTS ☐ PROGRESS PAYMENTS OR ☐ GUARANTEED LOANS

IV. DO YOU NOW HOLD ANY CONTRACT *(Or, do you have any independently financed (IR&D) projects)* FOR THE SAME OR SIMILAR WORK CALLED FOR BY THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify.):*

V. DOES THIS COST SUMMARY CONFORM WITH THE COST PRINCIPLES SET FORTH IN AGENCY REGULATIONS?

☒ YES ☐ NO *(If no, explain on reverse or separate page)*

See Reverse for Instructions and Footnotes

OPTIONAL FORM 60 (10-71)

November 9, 1972
ATTACHMENT NO. 1

EPA CONTRACT 68-02-0264
CE CONTRACT NO. 6472

OPTIONAL FORM 60

Combined Overfire Air & Gas Recirculation Systems

COST ELEMENT	#3 DIRECT LABOR			#4 LABOR OVERHEAD	
DEPT.	EST. HRS.	RATE/HR.	EST. COST	OH RATE	EST. COST
611 Eng.	15,000	5.35	80,125	90	72,125
631 Eng.	6,030	6.60	39,889	95	37,898
631 Tech.	2,620	4.85	12,697	95	12,062
516 Eng.	600	8.60	5,160	75	3,870
683 Eng.	130	7.55	985	160	1,570
683 Tech.	650	4.75	3,087	160	4,940
632 Service	800	6.55	5,250	111	5,830
641 Erection	1,680	8.15	13,652	108	14,740
Shop Labor	11,895	5.02	59,713	164	97,784
Metal Erect. Labor	44,850	7.92	355,212	24	84,318
			575,770		335,137

November 9, 1972
Attachment No. 2

Page 1

EPA CONTRACT 68-02-0264
CE CONTRACT NO. 6472

Combined Overfire Air & Gas Recirculation Systems Based on Estimated 1974 Costs

PHASE II

Task I Detail & Design

631 Eng.	40 hrs.	516	
611 Eng.	15,000	152,250	
			152,766

Task II Purchase & Fabricate

Raw Material & Shop Fab.	238,130	
Purchased Material	181,856	
Insurance	1,000	
		420,986

Task III Install Instruments; Baseline Tests

631 Eng.	400 hrs.	5,160	
631 Tech.	500 hrs.	4,725	
683 Eng.	50 hrs.	983	
683 Tech.	250 hrs.	3,087	
632 Service	160 hrs.	2,216	
Computer		2,000	
Material		1,000	
Freight		400	
Field Expenses		5,100	
Car Rental		2,000	
Air Travel		900	
			27,571

Combined
PHASE III

Task I Deliver Equipment & Modify Unit

631 Eng.	150 hrs.	1,935	
Material		500	
Field Expenses		5,504	
Car Rental		800	
Air Travel		200	
Freight		12,923	
Erect. Equip. Rental, Tools, Material & Consumables		112,350	
Insurance		1,000	
Field Labor			
Metal	44,850 hrs.	439,530	
Set., Insul. & Lag.	10600 hrs.	133,454	
641 Erection Rep.	1,680 hrs.	28,392	
			736,588

Combined
PHASE III (Continued)

Task II Final Test Preparation & Schedule

631 Eng.	240 hrs.	3,096	
631 Tech.	120 hrs.	1,134	
Material		500	
Freight		200	
Field Expense		1,100	
Car Rental		400	
Air Travel		400	
			6,830

Combined
PHASE IV

Task I Perform Unit Tests

631 Eng.	1280 hrs.	16,512	
631 Tech.	2000 hrs.	18,900	
632 Service	640 hrs.	8,864	
Material		1,500	
Field Expense		20,400	
Car Rental		6,400	
Air Travel		5,280	
			77,856

Task II Data Analysis

631 Eng.	2560 hrs.	33,024	
516 Eng.	600 hrs.	9,030	
683 Eng.	80 hrs.	1,572	
683 Tech.	400 hrs.	4,940	
Computer		10,000	
Freight		500	
Air Travel		500	
			59,566

PHASE V

Tasks I, II & III Application Guidelines

631 Eng.	1360 hrs.	17,544	
Computer		1,000	
Air Travel		500	
			19,044

TOTAL DIRECT COST & OVERHEAD	$1,501,207
G&A @4%	60,048
TOTAL ESTIMATED COST	$1,561,255
FEE @7-1/2%	117,094
GRAND TOTAL ESTIMATED COST & FEE	$1,678,349

CONTRACT PRICING PROPOSAL

(RESEARCH AND DEVELOPMENT)

Office of Management and Budget
Approval No. 29-RO184

This form is for use when *(i)* submission of cost or pricing data (see FPR 1-3.807-3) is required and *(ii)* substitution for the Optional Form 59 is authorized by the contracting officer.

PAGE NO.

NO OF PAGES

NAME OF OFFEROR: Combustion Engineering, Inc.

HOME OFFICE ADDRESS:
1000 Prospect Hill Road
Windsor, Conn. 06095

SUPPLIES AND/OR SERVICES TO BE FURNISHED: Eqpmt, matl, and labor to modify existing boiler. Engrs and techs to investigate combust mod techniques for NOx control by adding overfire air system only.

DIVISION(S) AND LOCATION(S) WHERE WORK IS TO BE PERFORMED: Windsor, Conn., Chattanooga, Tenn., St. Louis, Mo. and Monongahela, Pa.

TOTAL AMOUNT OF PROPOSAL: $ 753,070.00

GOV'T SOLICITATION NO.: EPA-68-02-0264

DETAIL DESCRIPTION OF COST ELEMENTS

1. DIRECT MATERIAL *(Itemize on Exhibit A)*			EST COST ($)	TOTAL EST COST	REFERENCE
a. PURCHASED PARTS			21,415		
b. SUBCONTRACTED ITEMS			83,103		
c. OTHER—*(1)* RAW MATERIAL			30,053		
(2) YOUR STANDARD COMMERCIAL ITEMS					
(3) INTERDIVISIONAL TRANSFERS *(At other than cost)*					
TOTAL DIRECT MATERIAL				134,571	
2. MATERIAL OVERHEAD *(Rate %X$ base=)*					
3. DIRECT LABOR *(Specify)*	ESTIMATED HOURS	RATE/HOUR	EST COST ($)		
See Attachment 1					
TOTAL DIRECT LABOR				262,661	
4. LABOR OVERHEAD *(Specify Department or Cost Center)*	O.H. RATE	X BASE =	EST COST ($)		
See Attachment 1					
TOTAL LABOR OVERHEAD				204,185	
5. SPECIAL TESTING *(Including field work at Government installations)*			EST COST ($)		
TOTAL SPECIAL TESTING					
6. SPECIAL EQUIPMENT *(If direct charge) (Itemize on Exhibit A)*					
7. TRAVEL *(If direct charge) (Give details on attached Schedule)*			EST COST ($)		
a. TRANSPORTATION			25,640		
b. PER DIEM OR SUBSISTENCE			28,690		
See Exhibit A — *TOTAL TRAVEL*				54,330	
8. CONSULTANTS *(Identify—purpose—rate)*			EST COST ($)		
TOTAL CONSULTANTS					
9. OTHER DIRECT COSTS *(Itemize on Exhibit A)*				17,840	
10. *TOTAL DIRECT COST AND OVERHEAD*				673,587	
11. GENERAL AND ADMINISTRATIVE EXPENSE *(Rate* 4 *% of cost element Nos.)*				26,943	
12. ROYALTIES					
13. *TOTAL ESTIMATED COST*				700,530	
14. FEE OR PROFIT				52,540	
15. *TOTAL ESTIMATED COST AND FEE OR PROFIT*				753,070	

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OPTIONAL FORM 60
October 1971
General Services Administration
FPR 1-16.806
5060-101

This proposal is submitted for use in connection with and in response to *(Describe RFP, etc.)*

EPA Contract 68-02-0264

and reflects our best estimates as of this date, in accordance with the Instructions to Offerors and the Footnotes which follow.

TYPED NAME AND TITLE
R. F. Swope
Contract Administrator

SIGNATURE

NAME OF FIRM
Combustion Engineering, Inc.

DATE OF SUBMISSION
Oct. 25, 1972

EXHIBIT A—SUPPORTING SCHEDULE *(Specify. If more space is needed, use reverse)*

COST EL NO.	ITEM DESCRIPTION *(See footnote 5)*		EST COST ($)
1a	Insulation	10,500	
1a	Controls	7,980	
1a	Instrumentation	2,935	21,415
1b	Setting, Insulation, and Lagging Erection Equip.	13,000	
1b	Setting, Insulation, and Lagging Erection Labor	43,668	
1b	Metal Erect. Equip. Rental, Tools, Consumables	26,435	83,103
1c	Ductwork	14,740	
1c	Gates and Dampers	7,618	
1c	Boiler Modification Tube Inserts	697	
1c	Structural Steel	6,998	30,053
7a	Freight 9,500, Car Rental 9,200, and Air Travel 6,940		25,640
9	Insurance	1,340	
9	Computer	13,000	
9	Misc Material	3,500	17,840

I. HAS ANY EXECUTIVE AGENCY OF THE UNITED STATES GOVERNMENT PERFORMED ANY REVIEW OF YOUR ACCOUNTS OR RECORDS IN CONNECTION WITH ANY OTHER GOVERNMENT PRIME CONTRACT OR SUBCONTRACT WITHIN THE PAST TWELVE MONTHS?

☒ YES ☐ NO *(If yes, identify below.)*

NAME AND ADDRESS OF REVIEWING OFFICE AND INDIVIDUAL
AEC, Chicago Operations Office

TELEPHONE NUMBER/EXTENSION

II. WILL YOU REQUIRE THE USE OF ANY GOVERNMENT PROPERTY IN THE PERFORMANCE OF THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify on reverse or separate page)*

III. DO YOU REQUIRE GOVERNMENT CONTRACT FINANCING TO PERFORM THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify.)*: ☐ ADVANCE PAYMENTS ☐ PROGRESS PAYMENTS OR ☐ GUARANTEED LOANS

IV. DO YOU NOW HOLD ANY CONTRACT *(Or, do you have any independently financed (IR&D) projects)* FOR THE SAME OR SIMILAR WORK CALLED FOR BY THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify.)*:

V. DOES THIS COST SUMMARY CONFORM WITH THE COST PRINCIPLES SET FORTH IN AGENCY REGULATIONS?

☒ YES ☐ NO *(If no, explain on reverse or separate page)*

See Reverse for Instructions and Footnotes

Attachment No. 1
October 25, 1972

EPA Contract 68-02-0264
CE Contract 6472

Optional Form 60

Cost Element	#3 Direct Labor			#4 Labor Overhead	
Dept.	Est. Hours	Rate/Hr.	Est. Cost	O.H. Rate	Est. Cost
611 Eng.	8,800	$5.10	$ 44,930	90	$ 40,430
631 Eng.	5,440	6.30	34,312	95	32,600
631 Tech.	2,420	4.60	11,170	95	10,610
683 Eng.	125	7.20	900	160	1,440
683 Tech.	625	4.55	2,847	160	4,560
516 Eng.	560	8.20	4,592	75	3,444
632 Service	760	6.25	4,754	111	5,278
641 Erector	1,040	7.75	8,050	108	8,694
Metal Erect.	16,525	7.54	124,599	43	53,578
Shop	5,587	4.74	26,507	165	43,551
			$262,661		$204,185

Attachment No. 2
October 25, 1972
1 of 3

EPA Contract 68-02-0264
CE Contract 6472

Overfire Air System Only
Based on Estimated 1973 Costs

Phase II

Task I - Detail & Design

631 Engineer (40 hrs.)	$ 492	
611 Engineer (8,800 hrs.)	85,360	
		$ 85,852

Task II - Purchase & Fabricate

Raw Material & Shop Fab.	100,110	
Purchased Material	21,415	
Freight	4,200	
Insurance	340	
		126,065

Task III - Install Instruments baseline tests

631 Engineer (400 hrs.)	4,920	
631 Technician (500 hrs.)	4,500	
683 Engineer (50 hrs.)	935	
683 Technician (250 hrs.)	2,963	
Service Engineer (160 hrs.)	2,112	
Computer	2,000	
Material	1,000	
Freight	400	
Field Expenses	5,060	
Car Rental	2,000	
Air Travel	900	
		26,790

Phase III

Task I - Deliver Equipment & Modify Unit

631 Engineer (160 hrs.)	$ 1,968	
Material	500	
Field Expense	3,556	
Car Rental	800	
Air Travel	200	
Freight	4,200	
Erect. Equip. Rental, Tools, Material, & Consumables	39,435	
Insurance	1,000	
Field Labor		
Metal (16,525 hrs.)	178,177	
Set. Insul. & Lag (3,600 hrs.)	43,668	
641 Erection Rep. (1,040 hrs.)	16,744	$290,248

Task II - Final Test Preparation & Schedule

631 Engineer (240 hrs.)	2,952	
631 Technician (120 hrs.)	1,080	
Material	500	
Freight	200	
Field Expense	1,100	
Car Rental	400	
Air Travel	400	6,632

Phase IV

Task I - Perform Unit Tests

631 Engineer (1,200 hrs.)	14,760	
631 Technician (1,800 hrs.)	16,200	
Service Engineer (600 hrs.)	7,920	
Material	1,500	
Field Expenses	18,975	
Car Rental	6,000	
Air Travel	4,440	69,795

Attachment No. 2
October 25, 1972
3 of 3

Task II - Data Analysis

631 Engineer (2,400 hrs.)	$ 29,520	
516 Engineer (560 hrs.)	8,036	
683 Engineer (75 hrs.)	1,405	
683 Technician (375 hrs.)	4,444	
Computer	10,000	
Freight	500	
Air Travel	500	
		$ 54,405

Phase V

Tasks I, II, III -
Application Guidelines

631 Engineer (1,000 hrs.)	12,300	
Computer	1,000	
Air Travel	500	
		13,800
Total Direct Cost & Overhead		$673,587
G & A @ 4%		26,943
Total Estimated Cost		700,530
Fee @ 7 1/2%		52,540
Grand Total Estimated Cost & Fee		$753,070

CONTRACT PRICING PROPOSAL

(RESEARCH AND DEVELOPMENT)

Office of Management and Budget
Approval No. 29-RO184

This form is for use when *(i)* submission of cost or pricing data (see FPR 1-3.807-3) is required and *(ii)* substitution for the Optional Form 59 is authorized by the contracting officer.

PAGE NO.

NO. OF PAGES

NAME OF OFFEROR Combustion Engineering, Inc.

HOME OFFICE ADDRESS
1000 Prospect Hill Road
Windsor, Conn. 06095

SUPPLIES AND/OR SERVICES TO BE FURNISHED Eqpmt, matl, and labor to modify existing boiler. Engrs and techs to investigate combust mod techniques for NOx contr by adding flue gas recirc system only.

DIVISION(S) AND LOCATION(S) WHERE WORK IS TO BE PERFORMED Windsor, Conn., Chattanooga, Tenn., St. Louis, Mo. and Monongahela, Pa.

TOTAL AMOUNT OF PROPOSAL $ 1,093,487.00

GOV'T SOLICITATION NO. EPA-68-02-0264

DETAIL DESCRIPTION OF COST ELEMENTS

1. DIRECT MATERIAL *(Itemize on Exhibit A)*			EST COST ($)	TOTAL EST COST[1]	REFERENCE[2]
a. PURCHASED PARTS			159,370		
b. SUBCONTRACTED ITEMS			167,075		
c. OTHER—*(1)* ~~RAW MATERIAL~~			48,463		
(2) YOUR STANDARD COMMERCIAL ITEMS					
(3) INTERDIVISIONAL TRANSFERS *(At other than cost)*					
TOTAL DIRECT MATERIAL				374,908	
2. MATERIAL OVERHEAD[3] *(Rate %X$ base=)*					
3. DIRECT LABOR *(Specify)*	ESTIMATED HOURS	RATE/ HOUR	EST COST ($)		
See Attachment 1					
TOTAL DIRECT LABOR				357,423	
4. LABOR OVERHEAD *(Specify Department or Cost Center)*[3]	O.H. RATE	X BASE =	EST COST ($)		
See Attachment 1					
TOTAL LABOR OVERHEAD				191,038	
5. SPECIAL TESTING *(Including field work at Government installations)*			EST COST ($)		
TOTAL SPECIAL TESTING					
6. SPECIAL EQUIPMENT *(If direct charge) (Itemize on Exhibit A)*					
7. TRAVEL *(If direct charge) (Give details on attached Schedule)*			EST COST ($)		
a. TRANSPORTATION			20,953		
b. PER DIEM OR SUBSISTENCE			22,272		
TOTAL TRAVEL				43,225	
8. CONSULTANTS *(Identify—purpose—rate)*			EST COST ($)		
TOTAL CONSULTANTS					
9. OTHER DIRECT COSTS *(Itemize on Exhibit A)*				11,480	
10. *TOTAL DIRECT COST AND OVERHEAD*				978,074	
11. GENERAL AND ADMINISTRATIVE EXPENSE *(Rate* 4 *% of cost element Nos.)*[3]				39,123	
12. ROYALTIES[3]					
13. *TOTAL ESTIMATED COST*				1017,197	
14. FEE OR PROFIT				76,290	
15. *TOTAL ESTIMATED COST AND FEE OR PROFIT*				1093,487	

This proposal is submitted for use in connection with and in response to *(Describe RFP, etc.)*

EPA Contract 68-02-0264

and reflects our best estimates as of this date, in accordance with the Instructions to Offerors and the Footnotes which follow.

TYPED NAME AND TITLE
R. F. Swope
Contract Administrator

SIGNATURE

NAME OF FIRM
Combustion Engineering, Inc.

DATE OF SUBMISSION
Nov. 9, 1972

EXHIBIT A—SUPPORTING SCHEDULE *(Specify. If more space is needed, use reverse)*

COST EL NO.	ITEM DESCRIPTION *(See footnote 5)*		EST COST *($)*
1a	Insulation	21,830	
1a	Gas Recirc Fan	73,592	
1a	Gas Recirc Fan Motor	42,998	
1a	Controls	20,940	159,370
1b	Setting, Insulation and Lagging Erection Equip.	25,000	
1b	Setting, Insulation and Lagging Erection Labor	88,130	
1b	Metal Erection Equip. Rental, Tools, Consumables	53,945	167,075
1c	Ductwork	20,274	
1c	Gates and Dampers	16,948	
1c	Structural Steel	11,241	48,463
7a	Freight 9,113, Car Rental 6,000, and Air Travel 5,840		20,953
9	Insurance	1,630	
9	Computer	8,600	
9	Misc Material	1,250	11,480

I. HAS ANY EXECUTIVE AGENCY OF THE UNITED STATES GOVERNMENT PERFORMED ANY REVIEW OF YOUR ACCOUNTS OR RECORDS IN CONNECTION WITH ANY OTHER GOVERNMENT PRIME CONTRACT OR SUBCONTRACT WITHIN THE PAST TWELVE MONTHS?

☒ YES ☐ NO *(If yes, identify below.)*

NAME AND ADDRESS OF REVIEWING OFFICE AND INDIVIDUAL
AEC, Chicago Operations Office

TELEPHONE NUMBER/EXTENSION

II. WILL YOU REQUIRE THE USE OF ANY GOVERNMENT PROPERTY IN THE PERFORMANCE OF THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify on reverse or separate page)*

III. DO YOU REQUIRE GOVERNMENT CONTRACT FINANCING TO PERFORM THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify.):* ☐ ADVANCE PAYMENTS ☐ PROGRESS PAYMENTS OR ☐ GUARANTEED LOANS

IV. DO YOU NOW HOLD ANY CONTRACT *(Or, do you have any independently financed (IR&D) projects)* FOR THE SAME OR SIMILAR WORK CALLED FOR BY THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify.):*

V. DOES THIS COST SUMMARY CONFORM WITH THE COST PRINCIPLES SET FORTH IN AGENCY REGULATIONS?

☒ YES ☐ NO *(If no, explain on reverse or separate page)*

See Reverse for Instructions and Footnotes

OPTIONAL FORM 60 (10-71)

November 9, 1972
Attachment No. 1

EPA CONTRACT 68-02-0264
CE CONTRACT NO. 6472

Gas Recirculation System Only

OPTIONAL FORM 60

COST ELEMENT DEPT.	#3 DIRECT LABOR EST. HRS.	RATE/HR.	EST. COST	#4 LABOR OVERHEAD OH RATE	EST. COST
611 Eng.	6,200	5.35	33,120	90	29,810
631 Eng.	3,940	6.60	26,066	95	24,760
631 Tech.	1,340	4.85	6,483	95	6,160
516 Eng.	490	8.60	4,214	75	3,161
683 Eng.	65	7.55	492	160	785
683 Tech.	300	4.75	1,425	160	2,280
632 Service	560	6.55	3,676	111	4,080
641 Erection	1,240	8.15	10,076	108	10,880
Shop Labor	6,308	5.05	31,855	164	52,149
Metal Erection Labor	30,305	7.92	240,016	24	56,973
			357,423		191,038

November 9, 1972
Attachment No. 2

EPA CONTRACT 68-02-0264
CE CONTRACT NO. 6472

Gas Recirculation System Only. Based on Estimated 1974 Costs.

PHASE II

Task I Detail & Design

631 Eng.	40 hrs.	516	
611 Eng.	6200 hrs.	62,930	63,446

Task II Purchase & Fabricate

Raw Material & Shop Fab.	132,467	
Purchased Material	159,370	
Insurance	630	292,467

Task III Install Instruments, Baseline Tests	0

Gas Recirc.
PHASE III

Task I Deliver Equipment & Modify Unit

631 Eng.	80 hrs.	1,032	
Material		500	
Field Expenses		3,872	
Car Rental		200	
Air Travel		200	
Freight		8,513	
Erect. Equip., Tools, Material & Consumables		78,945	
Insurance		1,000	
Field Labor			
Metal	30305 hrs.	296,989	
S.I.L.	7000 hrs.	88,130	
641 Erector	1240 hrs.	20,956	500,337

Task II Final Test Preparation & Schedule

631 Eng.	120 hrs.	1,548	
631 Tech.	60 hrs.	547	
Material		250	
Freight		100	
Field Expense		550	
Car Rental		200	
Air Travel		200	3,395

Gas Recirc.
PHASE IV

Task I Perform Unit Tests

631 Eng.	1120 hrs.	14,448	
631 Tech.	1280 hrs.	12,096	
632 Serv. Eng.	560 hrs.	7,756	
Material		500	
Field Expenses		17,850	
Car Rental		5,600	
Air Travel		4,440	
			62,690

Task II Data Analysis

631 Eng.	2080 hrs.	26,832	
516 Eng.	490 hrs.	7,375	
683 Eng.	65 hrs.	1,277	
683 Tech.	300 hrs.	3,705	
Computer		8,100	
Freight		500	
Air Travel		500	
			48,289

Gas Recirc.
PHASE V

Tasks I, II & III Application Guidelines

631 Eng.	500 hrs.	6,450	
Computer		500	
Air Travel		500	
			7,450

TOTAL DIRECT COST & OVERHEAD	$ 978,074
G&A @4%	39,123
TOTAL ESTIMATED COST	$1,071,197
FEE @7-1/2%	76,290
GRAND TOTAL ESTIMATED COST & FEE	$1,093,487

CONTRACT PRICING PROPOSAL
(RESEARCH AND DEVELOPMENT)

Office of Management and Budget
Approval No. 29-RO184

This form is for use when (i) submission of cost or pricing data (see FPR 1-3.807-3) is required and (ii) substitution for the Optional Form 59 is authorized by the contracting officer.

PAGE NO.

NO. OF PAGES

NAME OF OFFEROR: Combustion Engineering, Inc.

HOME OFFICE ADDRESS:
1000 Prospect Hill Road
Windsor, Conn. 06095

DIVISION(S) AND LOCATION(S) WHERE WORK IS TO BE PERFORMED: Windsor, Conn., Chattanooga, Tenn., St. Louis, Mo., and Monongahela, Pa.

SUPPLIES AND/OR SERVICES TO BE FURNISHED: Eqpmt, matl, and labor to modify existing boiler. Engrs and techs to investigate combust mod techniques for NOx contr by adding over-fire air system only.

TOTAL AMOUNT OF PROPOSAL: $ 426,644.00

GOV'T SOLICITATION NO.: EPA-68-02-0264

DETAIL DESCRIPTION OF COST ELEMENTS

1. DIRECT MATERIAL *(Itemize on Exhibit A)*			EST COST ($)	TOTAL EST COST¹	REFERENCE²
a. PURCHASED PARTS			37,082		
b. SUBCONTRACTED ITEMS			21,245		
c. OTHER—*(1)* RAW MATERIAL			8,809		
(2) YOUR STANDARD COMMERCIAL ITEMS					
(3) INTERDIVISIONAL TRANSFERS *(At other than cost)*					
TOTAL DIRECT MATERIAL				67,136	
2. MATERIAL OVERHEAD¹ *(Rate %X$ base=)*					
3. DIRECT LABOR *(Specify)*	ESTIMATED HOURS	RATE/HOUR	EST COST ($)		
See Attachment 1					
TOTAL DIRECT LABOR				137,575	
4. LABOR OVERHEAD *(Specify Department or Cost Center)*¹	O.H. RATE	X BASE =	EST COST ($)		
See Attachment 1					
TOTAL LABOR OVERHEAD				110,788	
5. SPECIAL TESTING *(Including field work at Government installations)*			EST COST ($)		
TOTAL SPECIAL TESTING					
6. SPECIAL EQUIPMENT *(If direct charge) (Itemize on Exhibit A)*¹					
7. TRAVEL *(If direct charge) (Give details on attached Schedule)*			EST COST ($)		
a. TRANSPORTATION			22,226		
b. PER DIEM OR SUBSISTENCE			21,800		
TOTAL TRAVEL				44,026	
8. CONSULTANTS *(Identify—purpose—rate)*			EST COST ($)		
TOTAL CONSULTANTS					
9. OTHER DIRECT COSTS *(Itemize on Exhibit A)*				7,275	
10. *TOTAL DIRECT COST AND OVERHEAD*				366,800	
11. GENERAL AND ADMINISTRATIVE EXPENSE *(Rate* 8.2 *% of cost element Nos.)*¹				30,078	
12. ROYALTIES³					
13. *TOTAL ESTIMATED COST*				396,878	
14. FEE OR PROFIT				29,766	
15. *TOTAL ESTIMATED COST AND FEE OR PROFIT*				426,644	

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OPTIONAL FORM 60
October 1971
General Services Administration
FPR 1-16.806
5060-101

This proposal is submitted for use in connection with and in response to *(Describe RFP, etc.)*

EPA Contract 68-02-0264

and reflects our best estimates as of this date, in accordance with the Instructions to Offerors and the Footnotes which follow.

TYPED NAME AND TITLE R. F. Swope Contract Administrator	SIGNATURE
NAME OF FIRM Combustion Engineering, Inc.	DATE OF SUBMISSION April 19, 1973

EXHIBIT A—SUPPORTING SCHEDULE *(Specify. If more space is needed, use reverse)*

COST EL NO.	ITEM DESCRIPTION *(See footnote 5)*		EST COST *($)*
1a	Insulation	1,995	
1a	Controls	2,152	
1a	Instrumentation	32,935	37,082
1b	Setting, Insulation, and Lagging Erection Equip.	2,359	
1b	Setting, Insulation, and Lagging Erection Labor	8,486	
1b	Metal Erection Equip. Rental, Tools, Consumables	10,400	21,245
1c	O. F. A. Registers	4,284	
1c	Hot Air Ducts	1,860	
1c	Boiler Modification Tube Inserts	697	
1c	Structural Steel	1,968	8,809
7a	Freight 2,126, Car Rental 13,500, and Air Travel 6,600		22,226
9	Insurance	1,175	
9	Computer	2,600	
9	Misc Material	3,500	7,275

I. HAS ANY EXECUTIVE AGENCY OF THE UNITED STATES GOVERNMENT PERFORMED ANY REVIEW OF YOUR ACCOUNTS OR RECORDS IN CONNECTION WITH ANY OTHER GOVERNMENT PRIME CONTRACT OR SUBCONTRACT WITHIN THE PAST TWELVE MONTHS?

☒ YES ☐ NO *(If yes, identify below.)*

NAME AND ADDRESS OF REVIEWING OFFICE AND INDIVIDUAL AEC, Chicago Operations Office	TELEPHONE NUMBER/EXTENSION

II. WILL YOU REQUIRE THE USE OF ANY GOVERNMENT PROPERTY IN THE PERFORMANCE OF THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify on reverse or separate page)*

III. DO YOU REQUIRE GOVERNMENT CONTRACT FINANCING TO PERFORM THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify.)*: ☐ ADVANCE PAYMENTS ☐ PROGRESS PAYMENTS OR ☐ GUARANTEED LOANS

IV. DO YOU NOW HOLD ANY CONTRACT *(Or, do you have any independently financed (IR&D) projects)* FOR THE SAME OR SIMILAR WORK CALLED FOR BY THIS PROPOSED CONTRACT?

☐ YES ☒ NO *(If yes, identify.)*:

V. DOES THIS COST SUMMARY CONFORM WITH THE COST PRINCIPLES SET FORTH IN AGENCY REGULATIONS?

☒ YES ☐ NO *(If no, explain on reverse or separate page)*

See Reverse for Instructions and Footnotes

Optional Form 60
Attachment No. 1
April 19, 1973

OVERFIRE AIR SYSTEM ONLY

Estimated 1973 Costs

Cost Element		#3 Direct Labor		#4 Labor Overhead	
Dept.	Est. Hours	Rate/Hr.	Est. Cost	O.H. Rate	Est. Cost
611 Eng.	2,030	$5.10	$10,353	104	$10,759
631 Eng.	240	6.20	1,494	89.5	1,338
631 Tech.	520	4.45	2,308	89.5	2,060
Shop	2,513	4.66	11,700	166	19,414
			$25,855		$33,571

Estimated 1974 Costs

Cost Element		#3 Direct Labor		#4 Labor Overhead	
Dept.	Est. Hours	Rate/Hr.	Est. Cost	O.H. Rate	Est. Cost
631 Eng.	5,320	$6.50	$34,536	89.5	$30,900
631 Tech.	1,880	4.65	8,730	89.5	7,814
683 Eng.	470	7.30	3,430	159	5,454
683 Tech.	1,170	4.70	5,485	159	8,730
516 Eng.	500	8.50	4,250	68	2,900
632 Service	660	6.70	4,432	110	4,874
641 Erector	256	7.90	2,022	112	2,266
Metal Erection	6,520	7.49	48,835	29	14,279
			$111,720		$77,279
1973 Estimated Costs			25,855		33,571
Total			$137,575		$110,788

Optional Form 60
Attachment No. 2
April 19, 1973

OVERFIRE AIR SYSTEM ONLY

Based on Estimated 1973 Costs

The figures following for Tasks I, II and III are based on estimated 1973 costs. Task II fabrication costs, are in effect until 8/74. All other tasks are based on estimated 1974 costs.

Task I - Detail & Design

631 Engineer (80 hrs.)	$ 944	
611 Engineer (2,030 hrs.)	21,112	
		$22,056

Task II - Purchase & Fabricate

631 Engineer (40 hrs.)	$ 472	
631 Technician (280 hrs.)	2,352	
Raw Material & Shop Fab.	39,923	
Purchased Material	37,082	
Insurance	175	
		$80,004

Task III - Install Test Equipment

631 Engineer (120 hrs.)	$ 1,416	
631 Technician (240 hrs.)	2,016	
Material	1,000	
Freight	400	
Field Expenses	2,200	
Car Rental	750	
Air Travel	600	
		$ 8,382

Task IV - Baseline Tests (Load & Ex. Air)

631 Engineer (480 hrs.)	$ 5,904	
631 Technician (280 hrs.)	2,464	
683 Engineer (75 hrs.)	1,418	
683 Technician (210 hrs.)	2,551	
Service Engineer (80 hrs.)	1,128	
Computer	1,000	
Field Expenses	3,400	
Car Rental	2,500	
Air Travel	800	
		$21,165

Task V - Baseline Tests (Bias Firing)

631 Engineer (480 hrs.)	$ 5,904	
631 Technicians (280 hrs.)	2,464	
683 Engineer (75 hrs.)	1,418	
683 Technicians (210 hrs)	2,551	
Service Engineer (80 hrs.)	1,128	
Computer	1,000	
Field Expenses	3,400	
Car Rental	2,500	
Air Travel	1,200	
		$21,565

Task VI - Deliver Equipment & Modify Unit

Material	$ 500	
Freight	1,526	
Erect. Equip. Rental, Tools, Material & Consumables	12,759	
Insurance	1,000	
Field Labor		
Metal (6,520 hrs.)	63,114	
Set. Insul. & Lag. (674 hrs.)	8,486	
641 Erection Rep. (256 hrs.)	4,288	
		$91,673

Task VII - Final Test Preparation & Schedule

631 Engineer (40 hrs.)	$ 492	
631 Technician (120 hrs.)	1,056	
Material	500	
Freight	200	
Field Expense	1,000	
Car Rental	750	
Air Travel	400	
		$ 4,398

Task VIII - Perform Unit Tests & Analyze Data

631 Engineer (3,280 hrs.)	$40,344	
631 Technician (1,200 hrs.)	10,560	
683 Engineer (320 hrs.)	6,048	
683 Technician (750 hrs.)	9,113	
516 Engineer (500 hrs.)	7,150	
Service Engineer (500 hrs.)	7,050	
Material	1,500	
Field Expenses	11,500	
Car Rental	7,000	
Air Travel	3,000	
		$103,265

Task IX - Application Guidelines

631 Engineer (1040 hrs.)	$12,792	
Computer	600	
Air Travel	600	
Field Expense	300	
		$14,292
Total Direct Cost & Overhead		$366,805
G&A @ 8.2%		30,078
Total Estimated Cost		396,878
Fee @ 7.5%		29,766
Grand Total Estimated Cost & Fee		$426,644

Optional Form 60
Attachment No. 3
April 19, 1973

OVERFIRE AIR SYSTEM ONLY

Metric System Option

Cost Element		#3 Direct Labor		#4 Labor Overhead	
Dept.	Est. Hours	Rate/Hr.	Est. Cost	O.H. Rate	Est. Cost
611 Eng.	600	$5.10*	$3,060	104	$3,180
631 Eng.	300	6.50**	1,950	89.5	1,740
516 Eng.	50	8.50**	425	68	290
			$5,435		$5,210

* 1973 Estimated Costs;Task I
**1974 Estimated Costs;Task VIII 300 hours,Task IX 50 hours

Total Direct Cost & Overhead	$10,645
G&A @ 8.2%	873
Total Estimated Cost	$11,518
Fee @ 7.5%	864
Grand Total Estimated Cost & Fee	$12,382

Combustion Engineering will use International Systems of Units (SI) per ASTM E-370-70, Metric Practice Guide. Arrangement and shop detail drawings will utilize a dual dimensioning system, i.e., U.S. customary units and SI units.

Optional Form 60
Attachment No. 4
April 19, 1973

OVERFIRE AIR SYSTEM ONLY

1974 Costs

Cost for each additional type of coal tested.

Cost Element		#3 Direct Labor		#4 Labor Overhead	
Dept.	Est. Hours	Rate/Hr.	Est. Cost	O.H. Rate	Est. Cost
631 Eng.	1160	$6.50	$7,530	89.5	$6,738
631 Tech.	520	4.65	2,416	89.5	2,160
			$9,946		$8,898

Total Direct Cost & Overhead	$18,844
G&A @ 8.2%	1,545
Total Estimated Cost	$20,389
Fee @ 7.5%	1,529
Grand Total Estimated Cost & Fee Per Test	$21,918

SECTION VI

ATTACHMENT V

COMBUSTION TECHNIQUE APPLICATION STUDY

NO_x Emission Control Technique Cost Ranges for Existing and New Steam Generators

PILOT FIELD TEST PROGRAM TO STUDY METHODS FOR REDUCTION OF NO_x FORMATION IN TANGENTIALLY COAL FIRED STEAM GENERATING UNITS

PREPARED FOR
THE ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK
NORTH CAROLINA 27711

April 4, 1973
Combustion Engineering, Inc.
1000 Prospect Hill Road
Windsor, Connecticut 06095
(203) 588-1911

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3.3 Detailed System Design Evaluation 181

3.3.1 New Units 182

3.3.2 Existing Units 183

Gas Recirculation and Overfire Air Duct System Figure 1A 185
" 1B 186
" 1C 187

Costs of NO_x Control Methods New Coal Fired Units Figure 2 188

Costs of NO_x Control Methods Existing Coal Fired Units Figure 3 189

1.0 SUMMARY

This report has been prepared in accordance with the requirements of Phase I, Task 4 of EPA Contract 68-02-0264. The design and economic evaluations expressed are based on Combustion Engineering, Inc.'s current knowledge and the cost estimates generated for the modification of Alabama Power Company, Barry Station No. 1 developed under Phase 1, Task 3 of Contract 68-02-0264.

Specifically, this report evaluates four possible methods of reducing NO_x emission levels from tangentially coal fired steam generators and estimates the cost trends for each method on both new and existing units. The reduction methods considered include overfire air, gas recirculation to the secondary air ducts and coal pulverizer/primary air system and furnace water injection. The cost trends for these methods are projected over a unit size range of 125 to 750 MW. Figures 1A, 1B and 1C illustrate the application of the gas recirculation and overfire air systems on an existing unit.

The results of the study indicate that for any given unit size (450 MW chosen for an example comparison) the lowest cost method is found to be overfire air which results in a .14 to .50 $/KW additional unit cost for a new or existing unit respectively.

This method incurs no loss in unit efficiency or increased operating expenses.

Gas recirculation introduced either through the secondary air ducts or the coal pulverizers and primary transport air system results in higher equipment costs than overfire air and requires additional power for fan operation.

Water injection introduced into the fuel firing zone of the unit is attractive from the standpoint of lower initial equipment costs, however, losses in unit efficiency resulting in increased fuel costs and significant water consumption make it the most expensive system to operate.

The use of either gas recirculation or water injection in existing units could result in a 10 to 20 percent decrease in load capability due to increased gas flow weights.

This represents a significant increase in unit capital cost per MW in addition to the cost of the modification. For example, a unit originally costing 300 $/KW operating at 80 percent load is actually costing 375 $/KW. Therefore, when modifying existing units gas recirculation rates greater than 15 percent do not seem practical.

2.0 CONCLUSIONS

1. The lowest cost method for reducing NO_x emission levels on new and existing units is the incorporation of an overfire air system. No additional operating costs are involved.

2. Gas Recirculation either to the windbox or coal pulverizers is a promising control system but is significantly more costly than overfire air and requires additional fan power. In existing units, the necessity to reduce unit capacity to maintain acceptable gas velocities imposes an additional penalty.

3. Gas recirculation to the coal pulverizers would cost approximately 15% less than windbox gas recirculation, however, this method may require increased excess air to maintain adequate combustion.

4. Water injection has initially low equipment costs, but due to high operating costs resulting from losses in unit efficiency, is the least desirable of the systems evaluated. This system may also require reduced unit capacity.

5. In general, the cost of applying any of the control methods studied to an existing unit is approximately twice that of a new unit design.

3.0 DISCUSSION

3.1 Control Method Selection

The following five modes of unit operation were chosen as potentially effective means for reduction of NO_x emissions from coal fired utility boilers.

The quantities of overfire air, gas recirculation and water injection selected for the economic evaluation, while reasonable, do not necessarily represent commercially feasible operation or control methods which would be recommended by Combustion Engineering, Inc.

1. Introducing 20 percent of the total combustion air over the fuel firing zone as overfire air.

2. Introducing 30 percent flue gas recirculation through the secondary air ducts and windbox compartments.

3. Combining the 20 percent overfire air and 30 percent flue gas recirculation of 1 and 2.

4. Introducing 17 percent flue gas recirculation through the transport air/coal pulverizer system.

5. Introducing water injection into the fuel firing zone at a rate of 5 percent of total evaporation.

3.2 Economic Evaluation

Economic comparisons of the five NO_x emission control methods are based on 1973 delivered and erected costs for the steam generators and associated equipment.

The cost estimates presented for the revision of existing units are based on studies performed on units within the 125 to 750 MW size range including those costs generated under Phase I, Task 3 for the Barry No. 1 unit. The cost estimates presented for incorporating control methods in new unit designs are based on Combustion Engineering experience and current practice for overfire air and gas recirculation systems. These cost ranges are shown on Figures 2 and 3.

As can be seen from these figures the cost ranges for existing units vary more widely than new units. This is due mainly to variations in unit design and construction which either hinder or aid the installation of a given control system. For example, an overfire air system may be designed as a windbox extension unless existing structural requirements and obstructions necessitate installation of a more costly system including extensive ductwork and individual air injection ports. The same condition exists for water injection systems when the need to maintain unit capacity dictates changes in unit ducting. Except where noted all system costs are estimated on a ± 10 percent basis. The cost range of the combined overfire air and windbox gas recirculation system was arrived at as the sum of the cost ranges of the individual systems. The cost ranges presented for existing units do not include any changes to heating surface as these changes must be calculated on an individual unit basis. Due to variations in existing designs, heating surfaces may increase, decrease or remain unchanged for a given control method.

At approximately 600 MW, single cell fired furnaces reach a practical size limit and divided furnace designs are employed. Since a divided tangentially fired furnace has double the firing corners of a single cell furnace, the costs of windboxes and ducts increase significantly as shown on figures 2 and 3. As shown, the costs of overfire air, windbox gas recirculation and windbox water injection increase from 30 to 50%.

3.3. DETAILED SYSTEM DESIGN EVALUATION

For the purpose of illustrating the effects on unit design of incorporating the NO_x control systems, a base unit is chosen. This base unit is then evaluated with respect to control system requirements both as a new and an existing design.

3.3.1 - New Units

3.3.1 - 1. Overfire Air System

This system provides for the introduction of 20 percent of the total combustion air through overfire air compartments which are designed as windbox compartment extensions. An extra 1.5 inches WG static head is included in the forced draft fan selection for flow distribution thereby increasing fan size. No other design changes from the base unit are required and the boiler efficiency is unchanged.

3.3.1 - 2. Flue Gas Recirculation Through the Secondary Air Duct and Windbox Compartments

The addition of 30 percent flue gas recirculation to the combustion air in the secondary air ducting and windbox will result in increasing duct, windbox and unit convective pass size. Superheat and reheater heating surface will decrease while economizer heating surface increases.

Additional gas recirculation ductwork, gas recirculation fans and dust collectors for fan protection must be provided. The unit efficiency remains unchanged, however, an additional auxiliary power requirement will be incurred to operate the gas recirculation fans.

3.3.1 - 3. Combination Overfire Air and Secondary Air Duct Gas Recirculation

The combination of Methods 1 and 2 results in a combination of the changes noted for the individual methods. No additional changes should be required.

3.3.1 - 4. Flue Gas Recirculation to the Transport Air/Coal Pulverizer System

Introduction of recirculated flue gas in place of air to the coal pulverizers will permit approximately 17 percent of the total gas weight to be recirculated at maximum continuous unit rating. Tempering is provided by having the gas fan inlet ducts drawing suction at both the hot and cold gas sides of the air preheater.

This control method requires that larger windboxes, additional gas recirculation ductwork, gas recirculation fans and dust collectors for fan protection be provided.

The boiler efficiency remains unchanged from the base unit, however, an additional auxiliary power requirement has been incurred to operate the gas recirculation fans. The gas recirculation fans would replace the primary air fans and the forced draft fan size would, therefore, have to be increased to provide the necessary combustion air. Coal pulverizer design and performance would remain unchanged.

3.3.1 - 5. Water Injection to the Firing Zone

Injection of spray water into the unit firing zone at a rate of 5 percent of boiler steam capacity will result in increased excess air requirements to insure proper fuel combustion, and a decrease in boiler efficiency of approximately 5 percent due to the increased excess air requirement and higher moisture losses. This injection rate is equivalent to 0.5 pounds of water per pound of coal fired and would be introduced through individual water nozzles located in the air compartments between each coal nozzle.

Due to the reduced unit efficiency, water injection and increased excess air, the flue gas mass flow increases by approximately 13 percent. With the furnace size remaining the same as the base unit, a larger convection pass results with decreased superheater and reheater heating surface and increased economizer heating surface.

The air preheater size will also increase due to the increased gas flow weight.

3.3.2 - Existing Units

3.3.2 - 1. Overfire Air System

This system provides for the introduction of 20 percent of the total combustion air through overfire air compartments. Depending on unit design these compartments can be fabricated as a windbox extension or they might require more extensive ducting and separate compartments due to structural requirements and interferences. Therefore, as shown on Figure 2,the costs for installing an overfire air system on existing units have considerably wider variation than for new unit designs. No other design changes from the base unit are required and efficiency remains unchanged.

3.3.2 - 2. Flue Gas Recirculation Through the Secondary Air Duct and Windbox Compartments

The addition of 30 percent gas recirculation to the combustion air in the secondary air ducting and windbox will require the addition of a complete gas recirculation system including fans, motors, dust collectors for fan protection and ductwork in addition to enlarging windboxes. Assuming that the convective pass velocities cannot exceed the original units, 30 percent gas recirculation would restrict maximum unit loading to 80 percent. Depending on unit design,convective pass heating surfaces may have to be added or removed if fuel nozzle tilt and desuperheater spray quantities are not adequate to maintain required steam temperatures. The unit efficiency remains unchanged, however, an additional auxiliary power requirement will be incurred to operate the gas recirculation fans.

3.3.2 - 3. Combination Overfire Air and Secondary Air Duct Gas Recirculation

The combination of Methods 1 and 2 results in a combination of the changes noted for the individual methods. No additional changes should be required.

3.3.2 - 4. Flue Gas Recirculation to the Transport Air/Coal Pulverizer System

Introduction of recirculated flue gas in place of air to the coal pulverizers will permit approximately 17 percent of the total gas weight to be recirculated at maximum continuous rating. Tempering is provided by having the gas fan inlet ducts drawing suction at both the hot and cold sides of the air preheater. This control method requires that more ductwork, gas recirculation fans and dust collectors for fan protection be added to the existing unit. The gas fans replace primary air fans and the forced draft fans on some units would, therefore, have to be larger. Coal pulverizer design and performance would remain unchanged.

However, to operate with the same convective pass velocities as the base unit with 17 percent gas recirculation,maximum unit load would be restricted to 85 percent of the base unit maximum load. At this reduced rating, existing fan capacities should be sufficient. Depending on unit design, convective pass heating surfaces may have to be added or removed if fuel nozzle tilt and desuperheat spray quantities are not adequate to maintain required steam temperatures.

The unit efficiency remains unchanged, however, an additional auxiliary power requirement will be incurred to operate the gas recirculation fans.

3.3.2 - 5. Water Injection to the Firing Zone

Injection of spray water into the unit firing zone at a rate of 5 percent of boiler steam capacity will result in increased excess air requirements to insure proper fuel combustion and a decrease in boiler efficiency of approximately 5 percent due to the increased excess air requirement and higher moisture losses. This injection rate is equivalent to 0.5 pounds of water per pound of coal fired and would be introduced through individual water nozzles located in the air compartments between each coal nozzle. Due to the lower boiler efficiency, the water injected and the higher excess air, the flue gas mass flow rate increases by 13 percent. Therefore, to operate with base unit convective gas velocities and the 5 percent water injection,load would be restricted to 90 percent of the base maximum continuous rating. At this reduced rating, the existing fans should have sufficient capacities.

Depending on unit design, convective pass heating surface might have to be added or removed if fuel nozzle tilt and desuperheater spray quantities are not sufficient to maintain required steam temperatures.

GENERAL NOTES
1. REMOVE EXISTING TURBINE VANES AND INSTALL AIR/GAS MIXING DEVICE.
2. USE WITH CE DWGS NE-714169 & NE-714170.

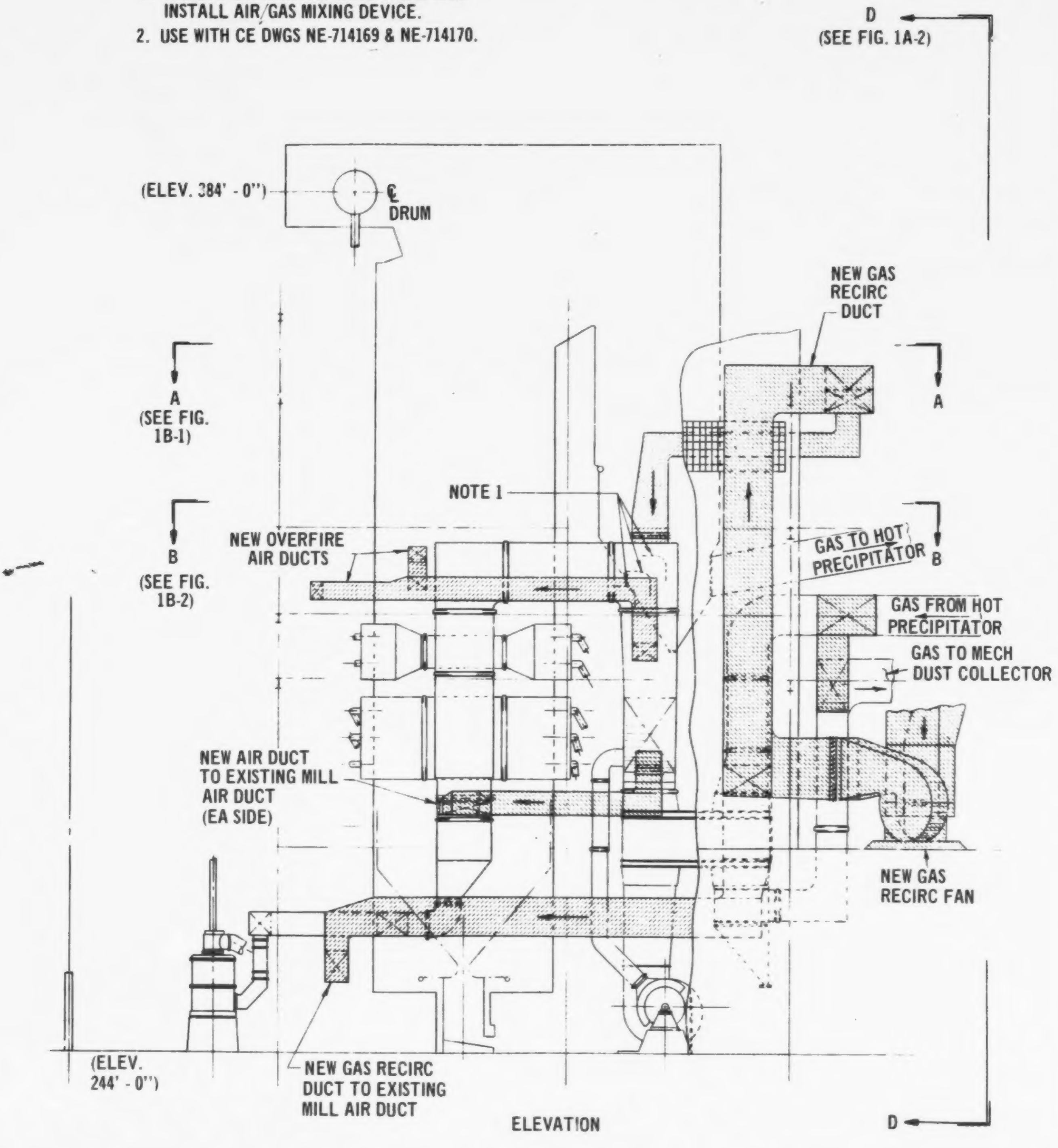
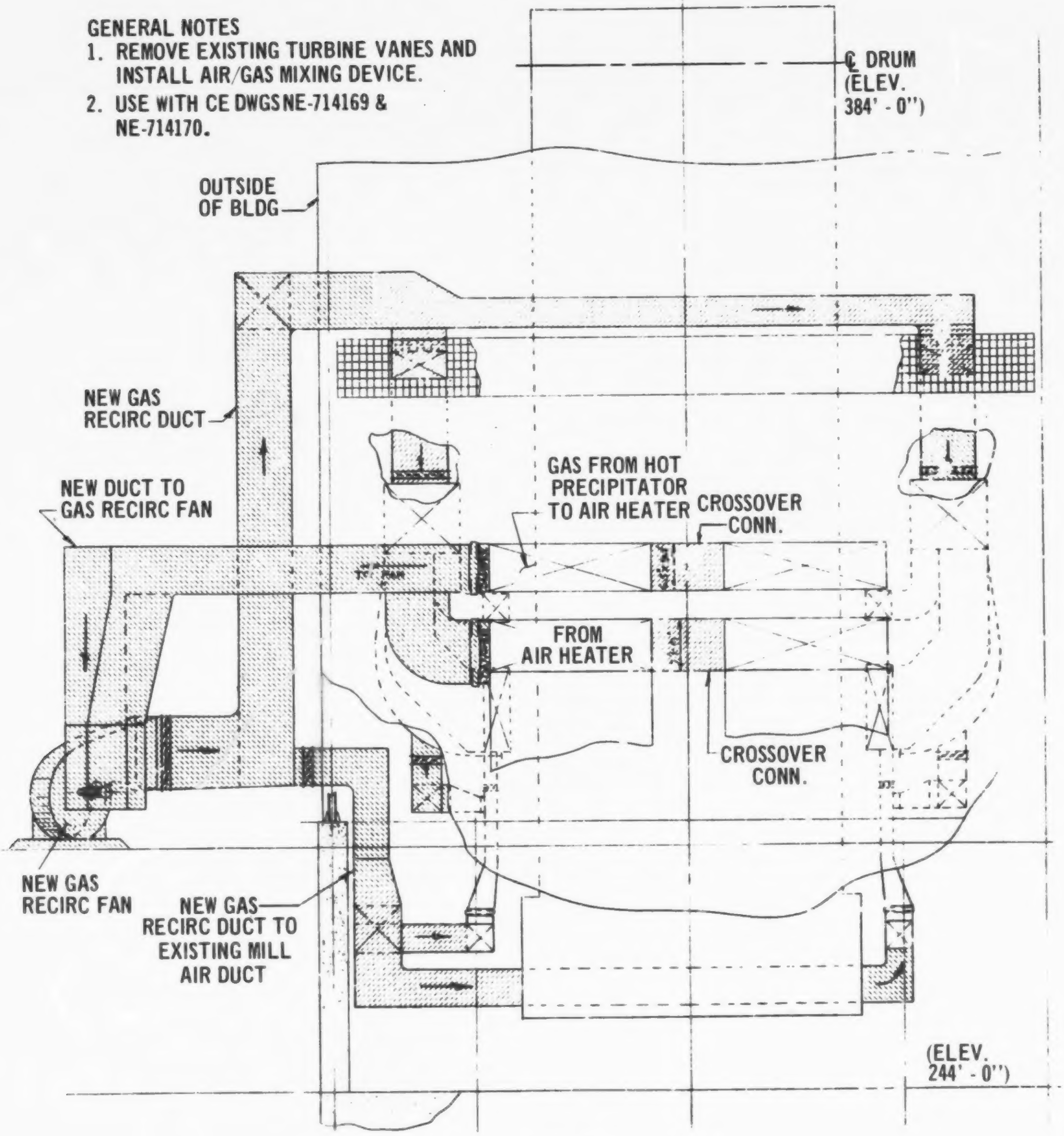

D
(SEE FIG. 1A-2)
(ELEV. 384' - 0")
℄ DRUM
NEW GAS RECIRC DUCT
A
(SEE FIG. 1B-1)
A
NOTE 1
B
(SEE FIG. 1B-2)
NEW OVERFIRE AIR DUCTS
GAS TO HOT PRECIPITATOR
B
GAS FROM HOT PRECIPITATOR
GAS TO MECH DUST COLLECTOR
NEW AIR DUCT TO EXISTING MILL AIR DUCT (EA SIDE)
NEW GAS RECIRC FAN
(ELEV. 244' - 0")
NEW GAS RECIRC DUCT TO EXISTING MILL AIR DUCT
ELEVATION
D

Figure 1A-1. Gas recirculation and overfire air duct systems for NO_x test program -- Gorgas No. 8, Alabama Power Co. (CE dwg NE - 714168-0).


GENERAL NOTES
1. REMOVE EXISTING TURBINE VANES AND INSTALL AIR/GAS MIXING DEVICE.
2. USE WITH CE DWGS NE-714169 & NE-714170.
℄ DRUM (ELEV. 384' - 0")
OUTSIDE OF BLDG
NEW GAS RECIRC DUCT
NEW DUCT TO GAS RECIRC FAN
GAS FROM HOT PRECIPITATOR TO AIR HEATER
CROSSOVER CONN.
FROM AIR HEATER
CROSSOVER CONN.
NEW GAS RECIRC FAN
NEW GAS RECIRC DUCT TO EXISTING MILL AIR DUCT
(ELEV. 244' - 0")

REAR ELEVATION D-D
(USE WITH FIG. 1A-1)

Figure 1A-2. Gas recirculation and overfire air duct systems for NO_x test program -- Gorgas No. 8, Alabama Power Co. (CE dwg NE-714168-0).

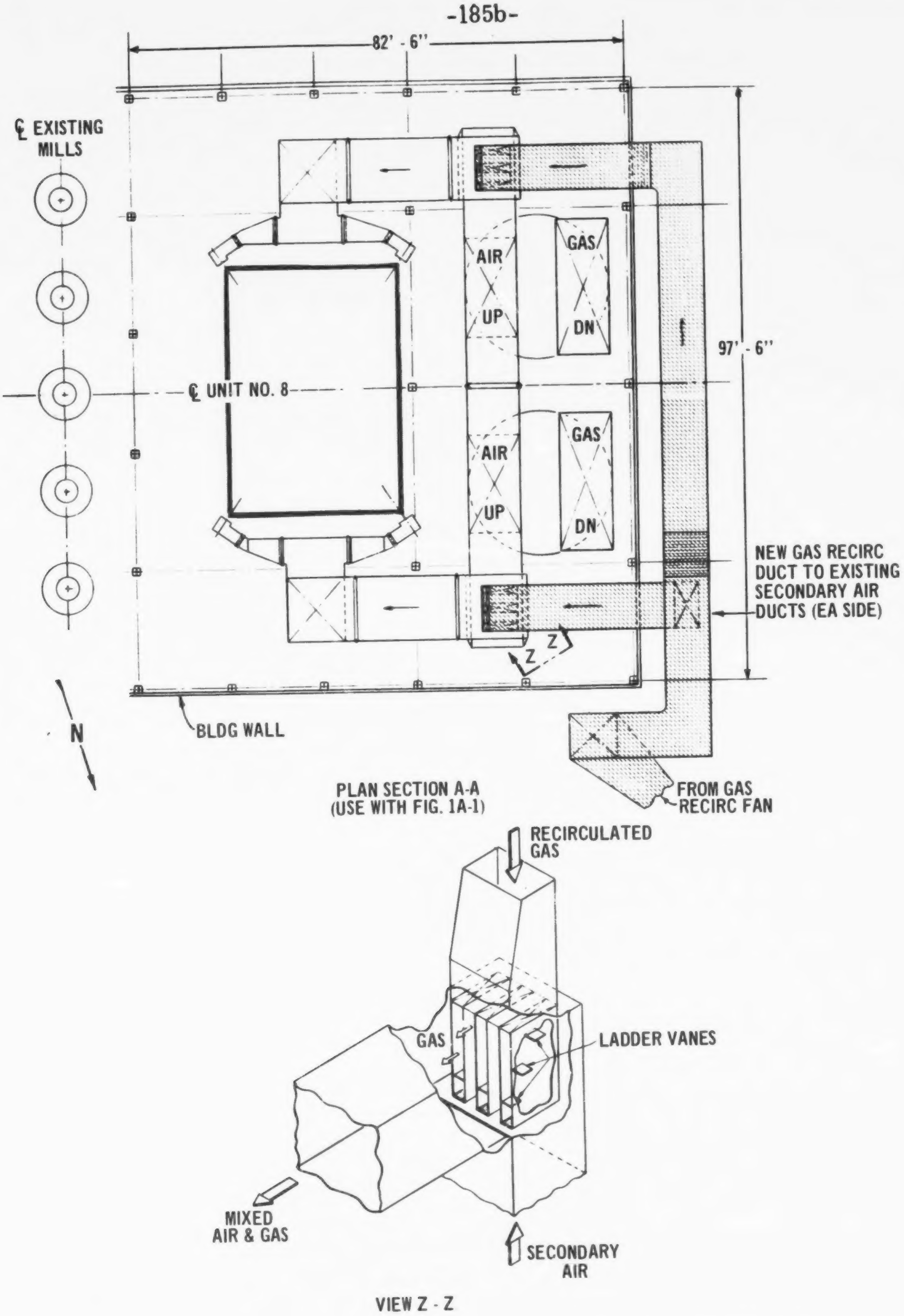
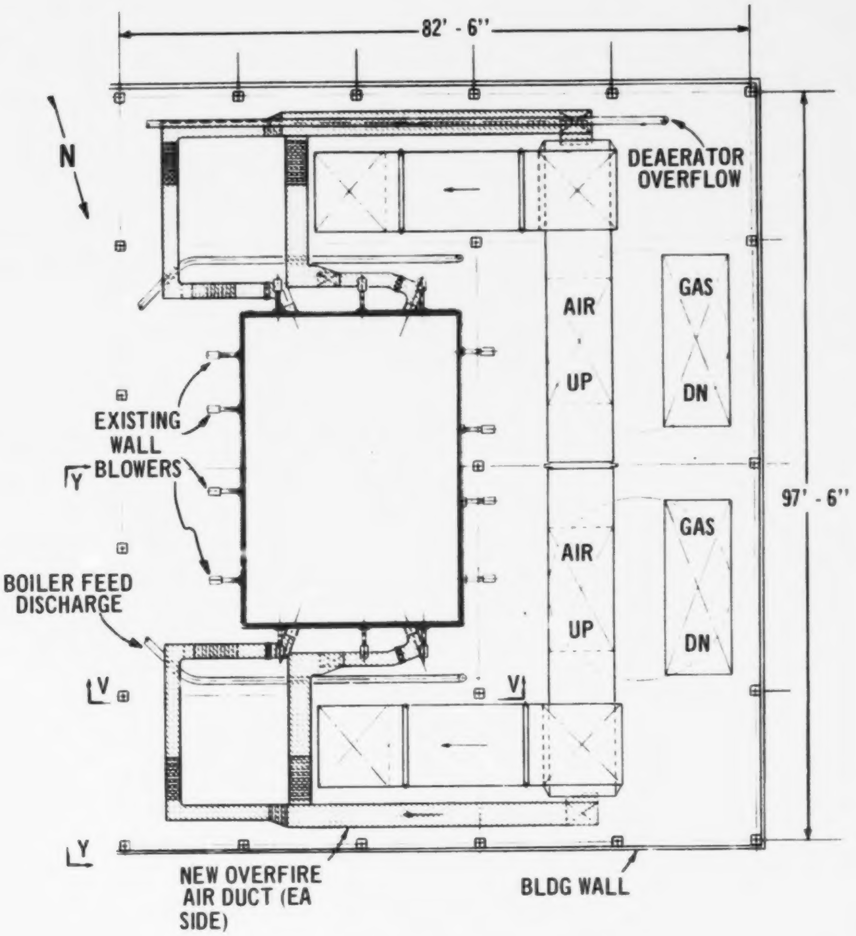
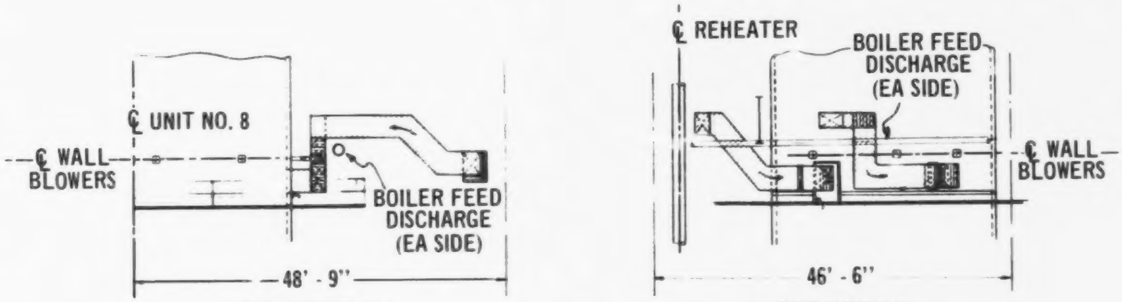

82' - 6"
℄ EXISTING MILLS
AIR
UP
GAS
DN
AIR
UP
GAS
DN
℄ UNIT NO. 8
97' - 6"
NEW GAS RECIRC DUCT TO EXISTING SECONDARY AIR DUCTS (EA SIDE)
Z
Z
N
BLDG WALL
PLAN SECTION A-A (USE WITH FIG. 1A-1)
FROM GAS RECIRC FAN
RECIRCULATED GAS
GAS
LADDER VANES
MIXED AIR & GAS
SECONDARY AIR
VIEW Z - Z

Figure 1B-1. Gas recirculation and overfire air duct systems for NO_x test program -- Gorgas No. 8, Alabama Power Co. (CE dwg NE-714169-0).


82' - 6"
N
DEAERATOR OVERFLOW
AIR UP
GAS DN
EXISTING WALL BLOWERS
Y
97' - 6"
AIR UP
GAS DN
BOILER FEED DISCHARGE
V
V
Y
NEW OVERFIRE AIR DUCT (EA SIDE)
BLDG WALL

PLAN SECTION B-B
(USE WITH FIG. 1A-1)


℄ UNIT NO. 8
℄ WALL BLOWERS
BOILER FEED DISCHARGE (EA SIDE)
48' - 9"
℄ REHEATER
BOILER FEED DISCHARGE (EA SIDE)
℄ WALL BLOWERS
46' - 6"

FRONT VIEW Y-Y

SIDE VIEW V-V

Figure 1B-2. Gas recirculation and overfire air duct systems for NO_X test program -- Gorgas No. 8, Alabama Power Co. (CE dwg NE-714169-0).

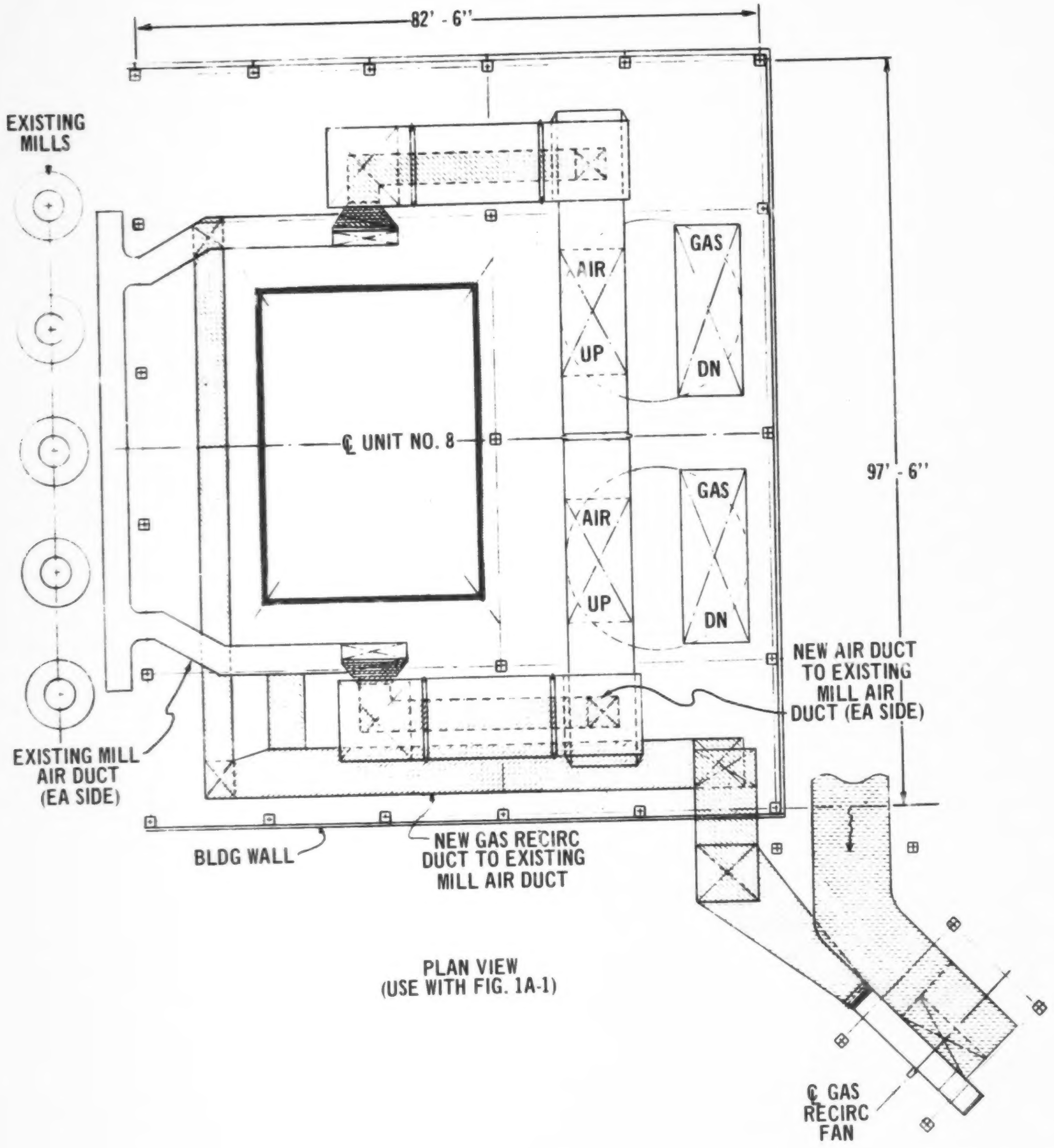
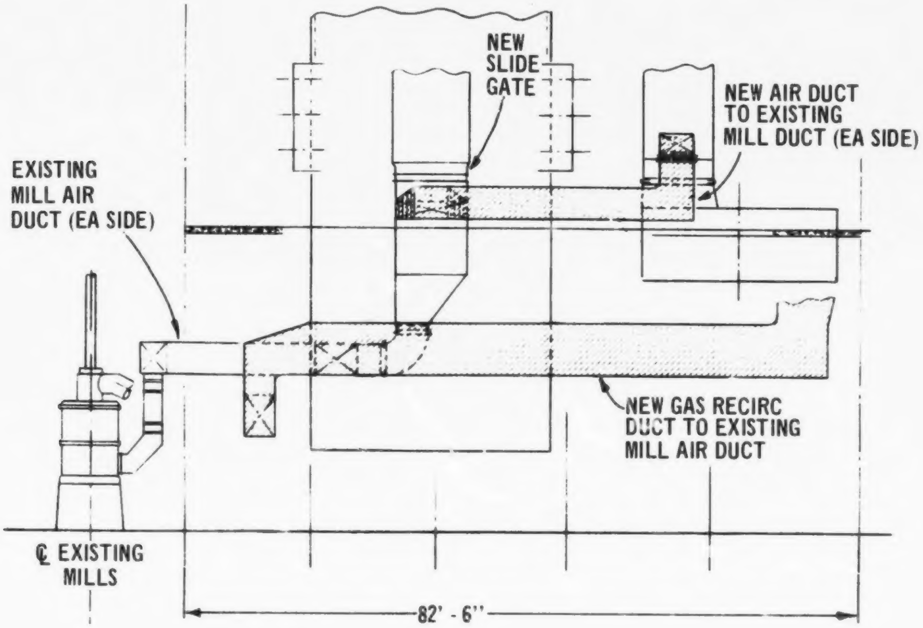
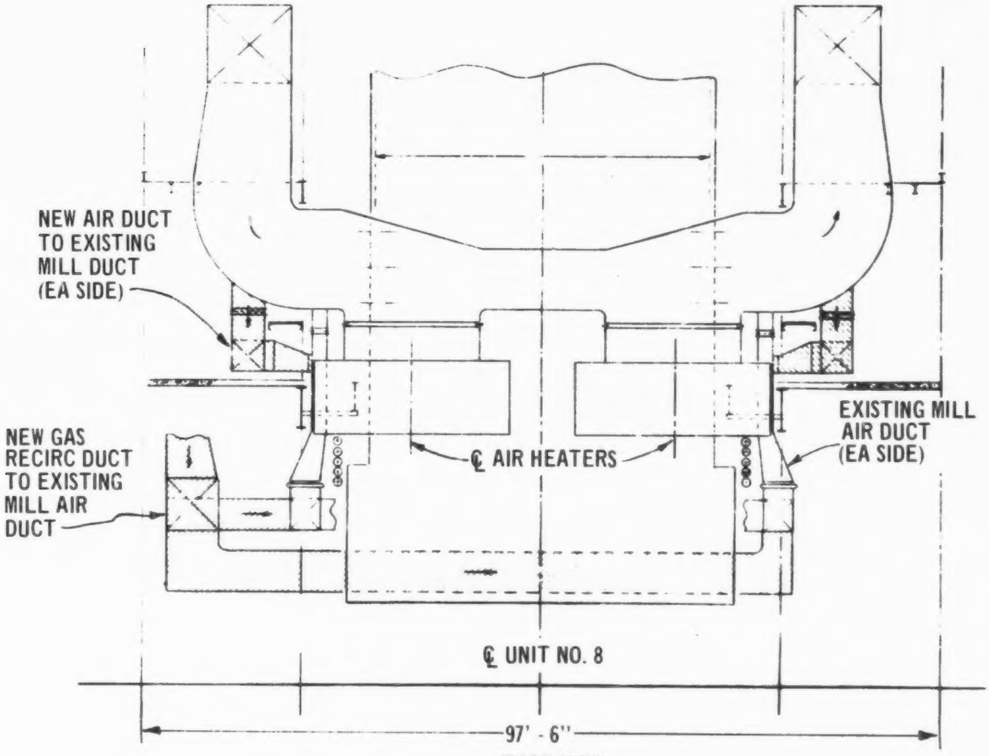

82' - 6"
97' - 6"
EXISTING MILLS
GAS
AIR
UP
DN
℄ UNIT NO. 8
GAS
AIR
UP
DN
NEW AIR DUCT TO EXISTING MILL AIR DUCT (EA SIDE)
EXISTING MILL AIR DUCT (EA SIDE)
BLDG WALL
NEW GAS RECIRC DUCT TO EXISTING MILL AIR DUCT
PLAN VIEW
(USE WITH FIG. 1A-1)
℄ GAS RECIRC FAN

Figure 1C-1. Gas recirculation and overfire air duct systems for NO_x test program -- Gorgas No. 8, Alabama Power Co. (CE dwg NE- 714170-0).


NEW SLIDE GATE
NEW AIR DUCT TO EXISTING MILL DUCT (EA SIDE)
EXISTING MILL AIR DUCT (EA SIDE)
NEW GAS RECIRC DUCT TO EXISTING MILL AIR DUCT
℄ EXISTING MILLS
82' - 6"

SIDE VIEW
(USE WITH FIG. 1A-1)


NEW AIR DUCT TO EXISTING MILL DUCT (EA SIDE)
NEW GAS RECIRC DUCT TO EXISTING MILL AIR DUCT
℄ AIR HEATERS
EXISTING MILL AIR DUCT (EA SIDE)
℄ UNIT NO. 8
97' - 6"

REAR VIEW
(USE WITH FIG. 1A-1)

Figure 1C-2. Gas recirculation and overfire air duct systems for NO_x test program -- Gorgas No. 8, Alabama Power Co. (CE dwg NE-714170-0).

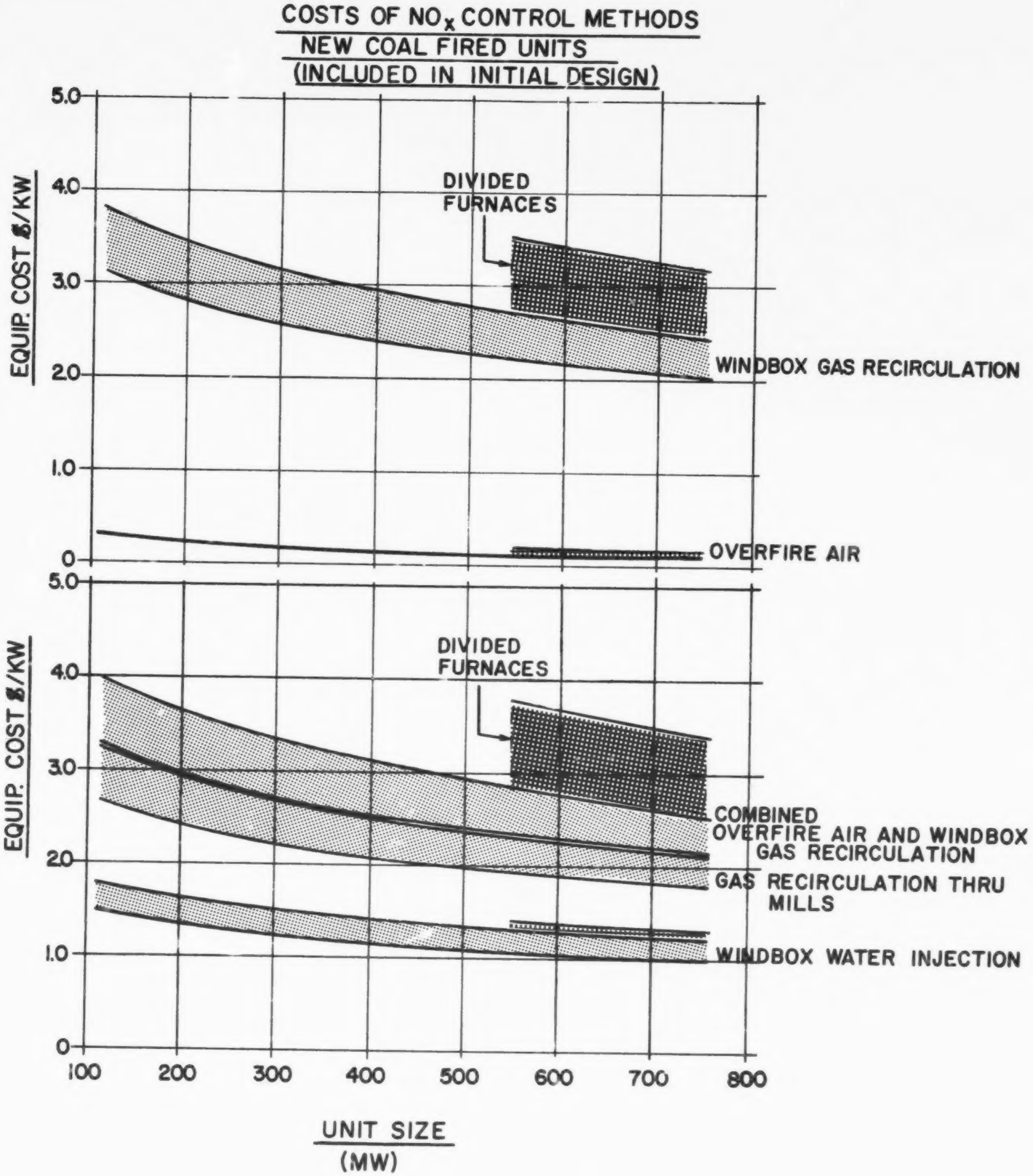

COSTS OF NO$_x$ CONTROL METHODS
NEW COAL FIRED UNITS
(INCLUDED IN INITIAL DESIGN)
EQUIP. COST $/KW
5.0
4.0
3.0
2.0
1.0
0
DIVIDED FURNACES
WINDBOX GAS RECIRCULATION
OVERFIRE AIR
EQUIP. COST $/KW
5.0
4.0
3.0
2.0
1.0
0
DIVIDED FURNACES
COMBINED OVERFIRE AIR AND WINDBOX GAS RECIRCULATION
GAS RECIRCULATION THRU MILLS
WINDBOX WATER INJECTION
100
200
300
400
500
600
700
800
UNIT SIZE
(MW)

FIGURE 2

COSTS OF NO_x CONTROL METHODS
EXISTING COAL FIRED UNITS
(HEATING SURFACE CHANGES NOT INCLUDED)

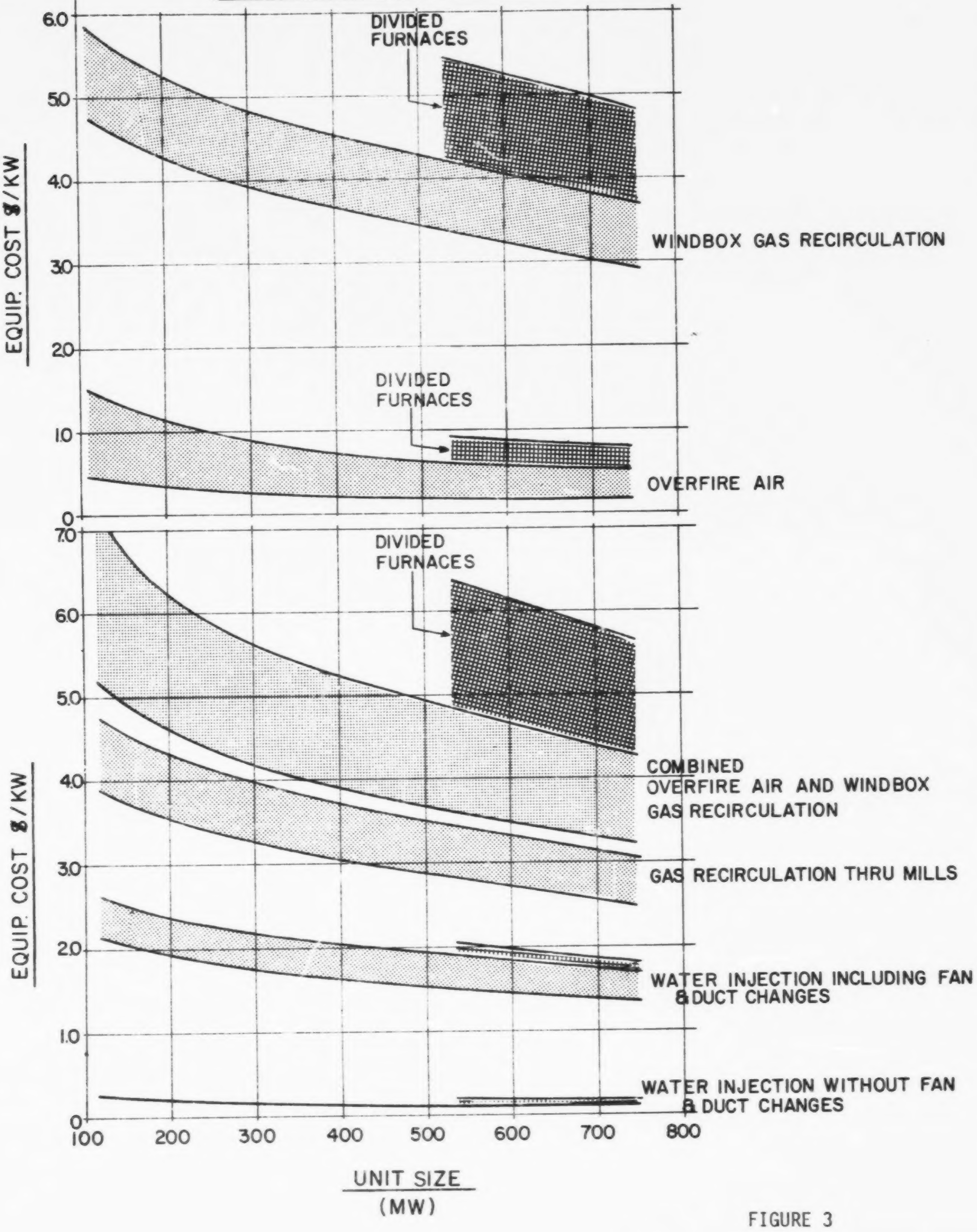


FIGURE 3